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Nos. 06-1457 & 06-1462

IN THE

Supreme Court of the United States

MORGAN STANLEY CAPITAL GROUP INC.,
Petitioner,

AND

CALPINE ENERGY SERVICES, L.P.,
AMERICAN ELECTRIC POWER SERVICE CORP.
AND
ALLEGHENY ENERGY SUPPLY CO., LLC,
Petitioners

v.

PUBLIC UTILITY DISTRICT NO. 1
OF SNOHOMISH COUNTY WASHINGTON, *et al.*,
AND
FEDERAL ENERGY REGULATORY COMMISSION,
Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Ninth Circuit

SUPPLEMENTAL JOINT APPENDIX

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PRICE MANIPULATION IN WESTERN MARKETS

FACT-FINDING INVESTIGATION OF
POTENTIAL MANIPULATION OF
ELECTRIC AND NATURAL GAS PRICES

DOCKET NO. PA02-2-000

Prepared by the Staff of the
Federal Energy Regulatory Commission

March 2003

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Executive Summary

Overview

This Report is the culmination of a yearlong effort by Commission Staff to determine whether and, if so, the extent to which California and Western energy markets were manipulated during 2000 and 2001. While Staff found significant market manipulation, this evidence does not alter the Commission's original conclusion, set forth in its December 15, 2000 Order, that significant supply shortfalls and a fatally flawed market design were the root causes of the California market meltdown.

The underlying supply-demand imbalance and flawed market design greatly facilitated the ability of certain market participants to engage in manipulation. In addition, the ability to pass through gas prices in electric power prices provided no check on gas buyers' willingness to pay.

For the first 2 years of its operation, the California market performed well and saved the state's customers billions of dollars. Only after the Pacific Northwest could no longer provide abundant supplies of low-cost hydropower to the regional market did the negative effects of too little infrastructure and poorly designed market rules adversely affect customers' bills.

A key conclusion of this Report is that markets for natural gas and electricity in California are inextricably linked, and that dysfunctions in each fed off one another during the crisis. Spot gas prices rose to extraordinary levels, facilitating the unprecedented price increase in the electricity market. Dysfunctions in the natural gas market appear to stem, at least in part, from efforts to manipulate price indices compiled by trade publications. Reporting of false data and wash trading are examples of efforts to manipulate published price indices. This Report makes recommendations for conditions the Commission should impose to ensure that price indices represent better barometers of actual prices.

In a related finding, Staff concludes that large-volume, rapid-fire trading by a single company, in what was incorrectly assumed to be a liquid market, substantially increased natural gas prices in California. To compensate for this, Staff reiterates the recommendation of its August 2002 Initial Report, which called for the Commission to alter the natural gas pricing methodology employed in the California

Refund Proceeding. Using Staff's recommended producing area plus transportation price, instead of published price indices, while accounting for scarcity and keeping electricity providers whole for the actual prices they paid for natural gas, would result in larger refunds to California.

This Report finds that many trading strategies employed by Enron and other companies were undertaken in violation of antigaming provisions of the Commission-approved tariffs for the Cal ISO and Cal PX. Staff recommends the Commission initiate proceedings to require guilty companies to disgorge profits associated with these tariff violations. This disgorgement would affect activities beginning January 1, 2000 through June 21, 2001, and not just those during the October 2, 2000 through June 21, 2001 refund period. These disgorgements would be in addition to the refunds resulting from the California Refund Proceeding.

A central mandate in undertaking this Staff fact-finding investigation was to determine whether the dysfunctional spot market for electricity had an impact on the forward prices reflected in long-term power supply agreements. The Staff's analysis finds that spot prices influenced forward prices negotiated during the January 1, 2000 through June 21, 2001 crisis period. The influence is greatest for contracts with 1- to 2-year terms.

Staff concludes that EnronOnline (EOL), which gave Enron proprietary knowledge of market conditions not available to other market participants, was a key enabler of wash trading. This created a false sense of market liquidity, which can cause artificial volatility and distort prices. Enron's informational trading advantage on EOL was lucrative; the company took large positions and was an active, successful speculator. Staff estimates Enron's speculative profits from EOL exceeded $500 million in 2000 and 2001. These speculative profits in financial instruments allowed Enron to sustain trading losses in physical trading. Staff further finds that Enron manipulated thinly traded physical markets to profit in financial markets. The Report recommends that the Commission prohibit the use of one-to-many trading platforms such as EOL and explicitly prohibit wash trading.

Staff concludes that prices in the California spot markets were affected by economic withholding and inflated bidding. Staff finds this violated the antigaming provisions of the Cal ISO and Cal PX tariffs and recommends proceedings to require disgorgement of profits associated with these inflated prices. This investigation did not address physical withholding of generation, an issue the Commission is addressing separately.

The balance of this executive summary discusses in greater detail the findings and recommendations in the body of this Report.

Background

On February 13, 2002, in Docket No. PA02-2-000, the Commission directed Staff to investigate whether any entity, including but not limited to Enron or any of its affiliates, manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over these prices and whether this resulted in unjust and unreasonable rates in long-term power sales contracts.

In August 2002, Staff released its Initial Report in Docket No. PA02-2-000.[1] In that Report, Staff recommended the initiation of various company-specific proceedings[2] to further investigate possible misconduct and recommended several generic changes to market-based tariffs to prohibit the deliberate submission of false information or the deliberate omission of material information, and to provide for the imposition of both refunds and penalties for violations. Staff also concluded that the most widely used published price indices were compiled without adequate standards or controls, were subject to attempted manipulation, could not be independently verified, and should not be used for setting the market-clearing prices in the California Refund Proceeding. Accordingly, Staff recommended the use of producing-area natural gas prices plus transportation. Finally, Staff analyzed the now infamous Enron trading strategies and found many of them to be forms of gaming based on price manipulation and the falsification of information.

Overall Organization and Primary Objectives of the Final Report

This Final Report achieves a multitude of objectives, many of which were listed in the Initial Report. It begins with two core objectives: to provide the Commission with our analysis of whether spot power prices in the West were just and reasonable in 2000–2001 and whether spot power prices adversely affected long-term power prices. While the Commission has already held that spot electric prices were unjust

[1]The Initial Report is available on the Commission's Web site at www.ferc.gov/electric/bulkpower/pa02-2/Initial-Report-PA02-2-000.pdf.
[2]These proceedings, which are currently pending before the Commission, are Docket Nos. EL03-113-000, EL03-114-000, and EL03-115-000.

and unreasonable, its refund methodology hinges on the use of a competitive gas input cost. Therefore, the first four chapters of this Report are dedicated to this critical gas issue and the fifth chapter addresses the correlation of spot electric prices to long-term electric prices. The remaining chapters address the other critical issues that help to explain the gas and electric markets in 2000 and 2001.

This Report reflects the views of Staff only. It has not been considered or adopted by the full Commission. In addition, whenever this Report concludes that prices were or appear to have been manipulated, it does so in the context of determining whether rates were unjust and unreasonable under the Federal Power Act or the Natural Gas Act or whether persons may have violated tariffs or regulations under those acts. Those acts do not require that intent be proven in order to make a determination that rates are or were unjust and unreasonable or that a person violated tariffs or regulations under those acts.

Chapter I: Context of the Gas and Electric Markets in the West

In this chapter, Staff provides essential background and context of the gas and electric markets in the West during 2000–2001. We analyze many factors that affected prices, including reduced hydro output, supply/demand imbalance, flawed market rules, illiquidity at a key gas trading point, stringent pipeline balancing rules, low gas storage levels, and pipeline constraints. We conclude that the electric and gas markets were so inextricably interrelated that their dysfunctions fed off each other.

Spot Gas Prices Reached Extraordinary Levels and Were Used to Set Clearing Prices for the Entire Electric Spot Market

The crucial conclusions of this chapter are that spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and that the effects of these inflated gas prices were greatly magnified because they were used to compute clearing prices paid by most California wholesale buyers for spot power. In Chapters II to IV we examine the causes in more detail.

Chapter II: Topock Was Illiquid—A Single Company Substantially Increased Prices

In this chapter, we conclude that Reliant engaged in a high-volume, rapid-fire trading strategy to purchase its physical spot gas needs at Topock. Reliant often bought and sold many times its needs in quick bursts, which significantly increased the price of gas in that market. We describe this as "churning" and define its characteristics later in the chapter. We use this term even though it has other connotations in securities or futures trading because it gives the best visual image of Reliant's behavior. Reliant's churning enabled it to reduce the overall cost of the gas it actually needed. Through its churning, Reliant profited by selling gas at or near the top of the price climb it caused. Reliant was often such a large presence at Topock (e.g., for the 3-month period from December 2000 to February 2001, nearly 50 percent of the spot gas trades at Topock on EOL were with Reliant) that its trading strategy moved the entire market price. Our analysis shows that the price of gas would have been lower by about $8.54/MMBtu in December 2000 and by about $1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant's churning. These inflated gas prices significantly influenced index prices and the clearing prices paid by most California wholesale buyers for spot power.

Staff concludes that these gas prices are not the result of competitive conditions and would not produce just and reasonable electric prices in the California Refund Proceeding. In Chapter IV of this Report, we recommend alternative gas prices for the Commission's consideration in the California Refund Proceeding.

Recommendations To Amend Gas Marketing Certificates and Generic Proceeding

Reliant's churning did not violate the blanket certificate under which it sold gas because Section 284.402 of the regulations contains no explicit guidelines or prohibitions. We recommend that Sections 284.284 and 284.402 of the regulations be amended to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. We also suggest a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of gas under Commission certificates.

Chapter III: Traders Attempted To Manipulate Price Indices Through False Reporting

Market participants provided false reports of natural gas prices and trade volumes to industry publications. These publications used the reports to compile price indices, and false reporting became epidemic. Five major traders (Williams, Dynegy, AEP, CMS, and El Paso Merchant Energy) have admitted that their employees falsified information provided to *Gas Daily* and *Inside FERC*, the most influential and relied-upon compilers of natural gas price indices. The false reporting included fabricating trades, inflating the volume of trades, omitting trades, and adjusting the price of trades.

The predominant motives for reporting false information were to influence reported gas prices, to enhance the value of financial positions or purchase obligations, and to increase reported volumes to attract participants by creating the impression of more liquid markets. Market participants that sold power in California, or that were affiliated with such sellers, also had incentives to manipulate reported prices because the clearing price set for power was based, in part, on natural gas spot prices.

Many traders acknowledged that false reporting was done openly in the industry. Some traders believed that the periodicals that prepared the indices were able to distinguish between fictional and accurate reports, but the Staff was unable to confirm that the periodicals could discern fictional trades and eliminate them from the index calculation. The widespread false reporting led Staff to conclude that reported prices did not reliably reflect market activity and, accordingly, that reported prices should not provide the basis for setting spot power clearing prices in the California Refund Proceeding.

Recommendations for Changes in the Reporting Process

Staff recommends various changes to the price reporting process. These changes will eliminate the ability and incentive of those reporting the data to manipulate the indices and will improve the price calculation methods.

- Only data that can be audited and verified by the Commission or other agencies can be used to construct the natural gas or electric price index.

- Data sent to firms publishing natural gas or electric price indices must be provided by the risk management office of the company, not the trading desk or a trader, and must be certified by the chief risk officer.
- The Commission should consider conditioning all electric market-based rate authorizations and blanket gas marketing certificate authorities on the companies providing complete, accurate, and honest information to any entity that publishes the price indices.
- The Commission should consider conditioning all electric and natural gas market-based rate authorizations on retaining all relevant data and information needed to reconstruct a published price index for a period of 3 years.
- Any published natural gas or electric price indices for Commission-jurisdictional transactions (e.g., pipeline tariff rates, market-based electric sales) must be subject to audit to ensure the accuracy of the data going in and the calculations themselves.
- The Commission should consider encouraging standard product definitions for published natural gas and electricity price indices and standard methodologies for calculating the price indices.

Certain Companies Must Demonstrate That They Currently Have Sound Procedures in Place

Staff recognizes the importance of accurate price indices in the overall health of competitive energy markets. The companies discussed at length in this chapter are significant participants in the U.S. electricity and natural gas markets. In order for the published price indices to be accurate and credible, firms publishing such indices must receive complete and accurate information from these companies. As such, Staff recommends that the following companies be required to demonstrate that they have corrected their internal processes for reporting trading data to the Trade Press or that they no longer sell natural gas at wholesale:

- Dynegy
- Aquila
- AEP
- El Paso Merchant Energy
- Williams
- Reliant
- Duke
- Mirant

- Coral
- CMS
- Sempra Energy Trading

At a minimum, these companies need to show the following:

- Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.
- The company has a clear code of conduct in place for reporting price information.
- All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).
- The company is cooperating fully with any government agency investigating its past price reporting practices.

Chapter IV: Spot Gas Prices Were Not the Product of a Well Functioning Competitive Market—They Should be Replaced for the California Refund Proceeding

In this and previous chapters of this Report, Staff concludes that California spot gas prices were artificially high due to market dysfunctions, illiquidity, misreporting, and a rupture causing an abnormal pipeline capacity shortage. The spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and reached levels that would never have been sustained in a competitive market. While some portion of these price levels reflected legitimate scarcity, we cannot calculate the portion attributable to scarcity alone. These inflated gas prices were used in the California Refund Proceeding to compute clearing prices for the entire electric spot power market. While there is no way to precisely replicate the level that spot gas prices would have reached in a competitive market, Staff recommends the use of producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. Over the 9-month refund period, Staff's proposal would reduce gas costs used in the refund formula by $7.03 in

southern California and $4.18 in northern California, or about $5.60 on average.

Many generators paid these distorted gas prices and fundamental fairness dictates that they be able to recover these costs. Accordingly, Staff also recommends that generators be made whole for the spot gas prices they paid, but that this recovery be on a dollar-for-dollar basis and not part of the market-clearing price.

Staff's proposal would increase the level of the refunds for California.

Chapter V: Spot Power Prices Adversely Affected Long-Term Power Prices

The vital link between the spot price and forward price for a commodity is the ability to store that commodity. In essence, someone can meet future needs by purchasing the commodity now and storing it for future consumption. As a result, the forward price that someone is willing to pay will approximate the cost of purchasing plus the carrying cost involved with stockpiling. Since the feasibility of storing electricity is very limited, we would expect to see little or no relationship between spot electric prices today and the forward price of electricity. Instead, forward prices should mostly reflect a buyer's expectations of prices in the future. Since natural gas is the marginal fuel in the West, forward gas prices should, in large part, explain forward power prices. Our analysis shows, however, that forward power prices negotiated during 2000–2001 in the western United States were significantly influenced by the then-current spot power prices. This tells us that the trauma of the dysfunctional spot power prices at that time so influenced buyers that they placed great weight on these prices in forming future expectations. The influence of spot prices on forward prices was the greatest for forward contracts with the shortest time to delivery (1-2 years) and varied by location. While Staff has found a statistically significant relationship, the magnitude of the impact is limited (that is, the impact of spot power prices on long-term power prices is clearly not dollar-for-dollar). Rather, a reduction of about one-third in the price of a 2-year forward contract would require a finding that spot power prices were three times above the just and reasonable level.

Chapter VI: Trading Strategies, Anomalous Behavior, Economic Withholding, and Inflated Bidding

In this chapter, we identify various entities that appear to have participated in some Enron price manipulation strategies; entered into profit-sharing arrangements with Enron, which masked Enron's real-market share; engaged in economic withholding; and raised clearing prices through inflated bidding. We also find evidence of price manipulation of the electric price index at Palo Verde and evidence that the spot power prices in the Pacific Northwest were inflated.

Violations of Cal ISO and Cal PX Tariffs

Since 1998, the Cal ISO and Cal PX tariffs have contained Market Monitoring and Information Protocols (MMIP). The MMIP include antigaming and anomalous market behavior provisions that identify various abuses and misconduct, such as taking unfair advantage of market rules, excessive pricing or bidding, and behavior not consistent with competitive markets, to the detriment of the efficiency of customers in the Cal ISO and Cal PX markets.

The Cal ISO and Cal PX initially submitted the MMIP (along with other protocols) for informational purposes only on October 31, 1997. The Commission, however, found that the protocols, including the MMIP, "govern a wide range of matters which traditionally and typically appear in agreements that should be filed with and approved by the Commission."[3] Therefore, the Commission accepted the protocols, including the MMIP, for filing, and directed the Cal ISO and Cal PX to post the protocols on their Internet sites and to file the complete protocols pursuant to Section 205 of the Federal Power Act within 60 days of the Cal ISO's Operations Date.[4] The Cal ISO and the Cal PX made that compliance filing on June 1, 1998. Accordingly, the MMIP has been part of the Cal ISO and Cal PX filed rate schedules since the Cal ISO's Operations Date (April 1, 1998).

Because of the fact that Part 2 of the MMIP specifically enumerates suspect practices, that Section 7.3 of the MMIP authorizes the Cal ISO to impose "sanctions and penalties" or to refer matters to the Commission for appropriate sanctions or penalties, and that the MMIP

[3] *Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,320 at 62,470-471 (1997).
[4] Id.

is part of the Cal PX's and Cal ISO's rate schedules on file with the Commission, Staff concludes that entities that transact through the Cal PX or Cal ISO and engage in such enumerated practices are in violation of those filed rate schedules. The stated objectives of the MMIP are to identify abuses of market power by giving particular scrutiny to a list of abusive practices and misconduct and to take corrective action, including sanctions and penalties. In Staff's view, the identified misconduct remains a violation of the Cal ISO's and Cal PX's filed rate schedules even if such formal procedures as referral outlined in the MMIP did not occur. The Commission can enforce a rate schedule on file even when there are processes in that rate schedule which, had they been used, would have assisted the Commission. Ultimately, the Commission can enforce a tariff with or without the assistance of a complaint or referral.

Orders To Show Cause

We conclude that many of these behaviors violated the Cal ISO and Cal PX tariffs and recommend that these entities be ordered to show cause why they should not disgorge revenues and why market-based authorizations should not be revoked. This disgorgement would be in addition to the refunds in the California Refund Proceeding.

Spot Power Prices in the Pacific Northwest Appear Inflated

Staff analysis of actual transaction data for the period January 2001 to June 2001 indicates that spot power prices in the Pacific Northwest appear to be excessive, as were spot power prices in the California portion of the integrated Western market.

Recommendation for Further Pacific Northwest Proceedings

Staff recommends that this Report and, in particular, the conclusions herein related to the Pacific Northwest spot power prices, be remanded to the Administrative Law Judge in Docket No. EL01-10-000.

Chapter VII: Wash Trading on EOL Created a False Impression of Liquidity

Wash trades were common on EOL across many products and locations. In fact, EOL often posted its willingness to buy and sell at the same price. This invited counterparties to wash trades, and these trades created a false sense of liquidity, which can distort prices.

Enron also manipulated prices on EOL by having affiliates on both sides of certain wash-like trades. This created artificial price volatility and raised prices.

Ban Wash Trading and Prohibit Reporting of Affiliate Trades to Indices

Staff recommends that the Commission establish specific rules banning any prearranged trades that wash and prohibiting the reporting of affiliate trades to industry indices.

Chapter VIII: Enron's Trading Practices on EOL Were Lucrative

EOL's one-to-many platform provided no transparency to the market. However, EOL provided Enron with a huge information advantage that Enron used to earn large profits.

EOL was not simply a conduit for transactions earning a moderate but steady profit on the spread between what it paid and what it sold. In fact, EOL took large positions and was an active, successful speculator. Enron used the information advantage acquired from its central position in physical markets to earn large speculative profits in financial products—more than $500 million in 2000 and 2001. Enron could sustain trading losses in the thinner physical markets as the cost to gain its information edge, which enabled it to earn large net profits.

Condition Market-Based Rates and Blanket Gas Certificates

We recommend that market-based rates and blanket gas certificates be conditioned to require sellers who use electronic platforms to use only those platforms with certain transparency and monitoring attributes. As discussed in this chapter and Chapter IX, Staff recommends that these platforms employ various monitoring tools, such as a churn alarm, to detect a large amount of buying and selling in a short timeframe.

Staff also recommends that information about all trigger events, e.g., identity of the market participants and the transaction data, be made available to the Commission through a real-time data feed.

Chapter IX: Enron Manipulated Thin Physical Markets for Profit in Financial Markets

Financial energy products are used to hedge risk on physical energy products, and the two are interrelated. Physical transaction prices dictate the pricing of financial products, i.e., financial products derive their value from the underlying physical market. The depth and liquidity of financial energy markets are far greater than those of physical markets.

The relationship between financial and physical energy products and the relatively thinner and less liquid physical markets provides opportunities to manipulate the physical market and profit in the financial markets. This is true regardless of whether the manipulation in the physical market raises or lowers prices for the physical commodity.

This Report analyzes an experiment by Enron to test a manipulation strategy and an actual manipulation by Enron using EOL. Enron manipulated the price of physical gas upward, then downward. Although the price change in the physical markets was only about $0.10/MMBtu, Enron profited due to the effect that this small change in the physical price had on its large financial position. Enron earned more than $3 million from this manipulation.

Show Cause Why the Commission Should Not Revoke Enron's Gas Marketing Certificate

We recommend that the Commission issue an order directing Enron to show cause why it should not have its blanket gas marketing certificate revoked.

Chapter X: Allegations That Williams Cornered the Market in Southern California Gas Are Unsubstantiated

Staff investigated allegations that Williams Energy Marketing & Trading Company cornered the natural gas market in California in January 2001. Based on the data, information, and documents reviewed, Williams purchased natural gas in amounts roughly

equivalent to its needs and had a small share of the natural gas demand. The allegations that Williams cornered the natural gas market in southern California for January 2001 are unsubstantiated.

Details of Staff Recommendations

Below we identify in one comprehensive list the specifics of Staff's recommendations for the Commission's consideration in addressing the issues arising out of this investigation. Staff recommends that the Commission:

- Amend Sections 284.284 and 284.402 of the regulations to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. (Chapters II and IX)
- Consider a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of natural gas under the Commission's blanket certificates. (Chapters II and IX)
- Condition all electric market-based rates and natural gas blanket marketing certificates on the companies providing complete, accurate, and honest information to any entity that publishes the price indices. (Chapter III)
- Condition all electric market-based rates and natural gas blanket marketing certificates on retaining all relevant data and information needed to reconstruct a published price index for a period of 3 years. (Chapter III)
- Require that any published price indices for Commission-jurisdictional transactions (e.g., pipeline tariff rates, market-based electric sales) must be subject to audit to ensure the accuracy of the data going in and the calculations themselves. (Chapter III)
- Require that only actual trade data be used to construct the price indices. (Chapter III)
- Require that data sent to firms publishing price indices be provided by the risk management office of the company, not the trading desk or a trader, and be certified by the chief risk officer. (Chapter III)
- Encourage standard product definitions for published natural gas and electricity price indices and standard methodologies for calculating the price indices. (Chapter III)
- Require Dynegy, Aquila, AEP, El Paso Merchant Energy, Williams, Reliant, Duke, Mirant, Coral, CMS, and Sempra Energy

Trading to demonstrate that they no longer sell natural gas at wholesale or that:

— Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.

— The company has a clear code of conduct in place for reporting price information.

— All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).

— The company is cooperating fully with any government agency investigating its past price reporting practices. (Chapter III)

- Use producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. (Chapter IV)
- Allow generators, many of which paid high gas prices, to recover these costs on a dollar-for-dollar basis, but not as part of the market-clearing price. (Chapter IV)
- For contracts that are subject to a just and reasonable standard of review in the ongoing consolidated complaint proceedings,[5] the Commission should send this analysis to the Administrative Law Judges to use as seen fit to resolve the complaints. (Chapter V)
- Conclude that the Cal ISO and Cal PX tariff antigaming and anomalous market behavior provisions identify various abuses and misconduct, such as taking unfair advantage of market rules, excessive pricing or bidding, and behavior not consistent with competitive markets; that these provisions authorize the imposition of sanctions and penalties by the Commission; that these provisions are part of the Cal ISO and Cal PX rate schedules on file; and that entities that engaged in the identified practices violated the Cal ISO and Cal PX filed rate schedules. (Chapter VI)
- Conclude that the Commission can enforce a rate schedule on file on its own motion without complaint or referral. (Chapter VI)

[5]Consolidated proceeding: *Nevada Power Company and Sierra Pacific Power Company v. Enron Power Marketing, Inc., El Paso Merchant Energy, and American Electricity Power Services Corporation; Nevada Power Company v. Morgan Stanley Capital Group, Calpine Energy Services, Reliant Energy Services, and Mirant Americas Energy Marketing, L.P.; Southern California Water Company v. Mirant Americas Energy Marketing, L.P.; and Public Utility District No. 1, Snohomish County, Washington v. Morgan Stanley Capital Group, Inc.*—Docket Nos. EL02-28-000, EL02-33-000, EL02-38-000, EL02-29-000, EL02-30-000, EL02-32-000, EL02-34-000, EL02-39-00, EL02-43-000, and EL02-56-000.

- Apply these provisions in issuing and implementing various show cause orders. (Chapter VI)
- Explicitly prohibit the use of false information as a condition for granting all market-based rate authorizations and blanket gas marketing certificates and add this condition to all open access transmission tariffs. (Chapter VI)
- Direct certain market participants identified in the January 6, 2003 Cal ISO Report[6] to show cause why their behavior did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- Direct AES/Williams, Dynegy/NRG, Mirant, Reliant, BPA, LADWP, Idaho Power, Powerex, and Enron to show cause why their prices from May to October 2000 did not constitute economic withholding or inflated bidding in violation of the antigaming and anomalous market behavior provisions in the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- Issue an order to Enron and the entities with whom it jointly engaged in the Enron trading strategies[7] (both public utilities and governmental entities) to show cause why this did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. (Chapter VI)
- Issue an order for Enron to show cause why its market-based rate authorization and its blanket gas marketing certificate authority should not be revoked. (Chapters VI and IX)

[6]Sempra/San Diego Gas and Electric; Morgan Stanley Capital Group; Coral Power, LLC; Powerex Corporation; Enron Power Marketing, Inc.; Enron Energy Services Inc.; Avista Energy Inc.; Pacific Gas and Electric Company; American Electric Power Services Corporation; Duke Energy Trading and Marketing; Mirant; Cargill-Alliant, LLC; Idaho Power Company; Puget Sound Energy; Dynegy; PGE Energy Services; Calpine Corporation; Modesto Irrigation District; City of Glendale, California; Arizona Public Service Company; Williams Energy Services Corporation; PacifiCorp; Automated Power Exchange; Bonneville Power Administration; Portland General Electric; Los Angeles Department of Water and Power; Aquila; Southern California Edison; Citizens Power Sales; Constellation Power Service; Sierra Pacific; Azusa; Riverside; Pasadena; Vernon; Salt River Project; and Reliant.

[7]Energy West; Montana Power Company; Puget Sound Power and Lighting Company; Powerex Corporation; City of Redding, California; City of Glendale, California; Colorado River Commission; Las Vegas Cogeneration; Washington Water Power Company (later named Avista); Valley Electric Association; Public Service of New Mexico; Grant Public Utility District; Grays Harbor Paper Company; Modesto Irrigation District of Northern California; and TOSCO.

- Order all jurisdictional entities to file any agreements with other entities that have any of the characteristics of the Enron joint partnership arrangements within 30 days. (Chapter VI)
- Order Reliant and BP Energy to show cause why their authorities to sell power at market-based rates should not be revoked by the Commission due to manipulation of electricity prices at Palo Verde. (Chapter VI)
- Remand this Report and, in particular, the conclusions herein related to the Pacific Northwest spot power prices, to the Administrative Law Judge in Docket No. EL01-10-000. (Chapter VI)
- Establish specific rules banning any form of prearranged wash trading and prohibiting the reporting of any affiliate trading activities through industry indices. (Chapter VII)
- Condition blanket gas marketing certificates, as well as electric market-based rates, to require that sellers who use trading platforms use only those trading platforms that agree to provide the Commission with full access to trade reporting and order book information for the trading systems and agree to adhere to appropriate monitoring requirements. (Chapters VII, VIII, and IX)
- Recommend that Congress consider giving direct authority to a Federal agency to ensure that electronic trading platforms for wholesale sales of electric energy and natural gas in interstate commerce are monitored and provide market information that is necessary for price discovery in competitive energy markets. (Chapters VII, VIII, and IX)
- State that the allegations that Williams Energy Marketing & Trading Company cornered the natural gas market in California in January 2001 are unsubstantiated. (Chapter X)
- Reevaluate the "simultaneous offer" rule that it uses to discipline affiliate transactions to ensure that it is effective and verifiable. (Initial Report)
- Require that all market-based rate tariffs include a specific prohibition against the submission of false information or the omission of material information to the Commission or to an entity such as an independent system operator, a regional transmission organization, or an approved market monitor. (Initial Report)
- Recommend that Congress expand the Commission's civil penalty authority that applies to jurisdictional companies that violate Commission orders, regulations, or tariffs. (Initial Report)

I. Manipulations in the California Natural Gas Spot Markets Forced Upward Pressure on Wholesale Electric Prices

California experienced extraordinarily high wholesale electric prices from the summer of 2000 through the winter of 2000–2001. High natural gas prices in California from the summer of 2000 through the winter of 2000–2001, in combination with accelerated electric demand, generation failures, flawed regulation, and transmission constraints combined to create these extraordinary wholesale electric prices. Gas-fired generation units, particularly peaking units, were often reliant on the spot gas market, due in part to policies of the California Public Utilities Commission (CPUC) that restricted their ability to enter into long-term contracts for natural gas. Operators of gas-fired generation units in California who paid higher spot market gas costs consequently raised their bids in the wholesale spot electric market. The effect of relatively inefficient generators (i.e., those with high heat rates), whose bids set the market price for all sellers, was to increase the impact of higher gas prices on wholesale electric prices.

Higher gas prices increased the revenues owed to power sellers and ultimately severely affected the state's electric customers.

While soaring demand for natural gas and flawed electric power market rules were the primary drivers of high gas prices, spot market manipulations contributed significantly. High wholesale electric prices were partially the result of specific behavior inimical to the efficient operation of a liquid and transparent competitive market.

Staff concludes that commodity trading in gas, particularly in southern California in the roughly 9-month period beginning in the summer of 2000, affected the very high electric prices. This conclusion is particularly germane to the methodology the Commission established in its July 25, 2002 Order to calculate potential refunds due to customers in the organized markets operated by the California ISO and the California PX for the period October 2, 2000 through June 20, 2001.[1] In that Order, the Commission established a mitigated price based on the marginal cost of the last unit dispatched to meet load in the California ISO's real-time market based on a daily spot gas price, as published in Financial Times Energy's *Gas Daily* publication.

We conclude that reliance on published spot market prices for natural gas at California delivery points is inappropriate for calculating

[1]See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service, 96 FERC ¶ 61,120 at 61,499, 61,516-517 (2001).

market-clearing power prices. In particular, these published prices reflect anomalous outcomes and manipulative activities not associated with a competitive market. Accordingly, they should not provide the basis for potential refunds to electric customers.

Sellers of wholesale power obtained prices that were augmented in an amount greater than the addition of higher gas input costs alone because, as indicated above, the market clearing price was set by the marginal (i.e., least efficient) unit. Thus, while sellers may have incurred higher spot market input costs for their gas-fired generation units, they obtained wholesale electric prices that magnified the effect of these higher gas costs because all generators were paid a single clearing price. Use of published gas index prices would result in a windfall to sellers if the published spot market prices for natural gas were used in the refund methodology.[2] Gas costs that were inflated by conditions not associated with competitive markets should not provide a source of profit to wholesale power sellers. Staff urges a different methodology for calculating electric prices for this period of market dysfunction.

Spot Market Natural Gas Prices at California Borders Were Extraordinarily High

Sharply higher gas costs beginning in the summer of 2000 and extending through the winter of 2000–2001 exacerbated already dire conditions for electric customers in California. Increased gas consumption pressured prices upward. Gas consumed for electric generation in California increased by 44 percent from May 2000 through October 2000, as compared to 1999 levels during the same period. In the entire West, the increase was 46 percent.[3] California's electric sector used 1.1 Tcf of gas in 2000, a 22-percent increase over consumption in 1999.[4] Total annual gas-fired generation in California

[2]Stated alternatively, since many sellers of wholesale power obtained electricity from relatively efficient generating units, these sellers realized a net producers' surplus; i.e., the difference between the minimum price at which the seller would be willing to sell power and the amount for which it actually sold. See Varian, Hal R., *Intermediate Microeconomics* (New York: W.W. Norton & Co., 1987), pp. 262–263. In a competitive market, producer surplus is a justified return earned by more efficient suppliers. However, because input prices were inflated due in part to manipulation, the associated producer surplus was also artificially inflated and hence the portion due to manipulation is unjustified. Staff cannot calculate the portion of the prices due to manipulation.

[3]Electric Power Monthly, Energy Information Administration, January 2001.

[4]Electric Power Annual, Energy Information Agency, p. 8 (Internet pagination).

rose by 31.7 percent in 2000, as compared to 1999 levels.[5] As noted above, gas-fired generators were willing to incur increased costs because they could pass these costs through in the form of higher charges for their outputs. Inefficient gas-fired units were called on by the California ISO to run to avoid power blackouts and this resulted in higher wholesale electric prices.

Higher demand was not the only driver of higher gas prices. In the August 2002 Initial Report, the Staff observed that spot market prices at the Southern California Border were detached from production basin prices; this indicates that transportation constraints contributed to a scarcity of gas supply relative to demand in the area, contributing to higher gas costs for California customers. Since the Commission regulates the maximum rate for transportation of natural gas by interstate pipelines, given sufficient interstate pipeline capacity and sufficient storage utilization, the cost of gas at the California border should not have significantly exceeded the production basin price of the gas plus the interstate transportation charge, unless scarcity and nonregulatory factors drove the imbalance.[6]

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[5] "U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply," Energy Information Administration (December 2001), p. 13 (Internet pagination).

[6] As the Commission has explained, its jurisdiction to regulate the prices charged by sellers of natural gas is subject to statutory limitations:

> The Natural Gas Policy Act of 1978 (NGPA) and the Natural Gas Wellhead Decontrol Act substantially narrowed the Commission's Natural Gas Act (NGA) jurisdiction over sales for resale, with the Wellhead Decontrol Act removing all "first sales" from the Commission's NGA jurisdiction as of January 1, 1993. First sales include all sales other than those by interstate or intrastate pipelines, LDCs, or their affiliates. In addition, Section 3(b) of the NGA provides that all sales of gas imported from countries with free trade agreements, such as Canada and Mexico, have first sale status even when sold by pipelines, LDCs, or affiliates. The end result of these various statutory provisions is that the only sales the Commission currently has jurisdiction to regulate are those for resale of domestic gas by pipelines, LDCs, or their affiliates.

Reporting of Natural Gas Sales to the California Market, 95 FERC ¶ 61,262 at 61,929 (2001) (footnotes omitted). In addition, in 1992, the Commission directed pipelines to separate their transportation and commodity sales services. See Order No. 636, FERC Stats. & Regs., Regulations Preambles (January 1991 to June 1996) ¶ 30,939 (1992). By unbundling these products, pipelines became more like common carriers. This reform, among others, increased efficiency by creating a largely transparent interstate transportation market in which pipelines were required to treat all shippers equally. According to one authority, natural gas prices have been lower since Federal deregulation of natural gas prices, although the volatility of those prices has increased. "Natural Gas: Analysis of Changes in Market Price," General Accounting Office, December 2002, p. 10.

California has separate natural gas markets in southern and northern California. The markets are separate because of limits on transportation capacity between the regions and, therefore, prices are often different in the respective regions. In southern California, limited transportation capacity and storage contributed to higher gas prices in the 2000–2001 period than in the prior year. In northern California, fewer transportation constraints, greater storage, and the ability of generators to hold firm transportation capacity resulted in lower spot market prices for natural gas. Although we discuss southern California and northern California natural gas prices and market conditions separately, our overall point is that dysfunctions in both regions render spot prices inappropriate as bases for electric refund calculations.

Most large natural gas customers in southern California, such as electric generation plants, could (1) buy bundled gas at the Southern California Border or (2) buy gas at the San Juan or Permian production basins (located roughly in the Four Corners area and west Texas, respectively) and arrange for transportation of the gas by interstate pipeline to the Southern California Border.[7] There would have been little reason to pay spot prices at the Southern California Border that exceeded the cost of natural gas purchased in one of the production basins plus the cost of transportation to the border, unless transportation was not readily available.

The CPUC's regulation of Southern California Gas Company (SoCalGas) impacted terms under which interstate pipeline capacity was purchased. For example, the CPUC limited SoCalGas to purchasing interstate pipeline capacity necessary to serve its core customers, which did not include independent generators. The CPUC also approved terms of service on SoCalGas' system that, for example, did not provide for firm transportation service on SoCalGas for independent generators. These aspects of the CPUC's regulation did not change the generators' option of buying at a production basin and shipping gas to the border (to the extent that interstate capacity was available) or buying a bundled product at the border. No matter which option generators elected, they would have been able to obtain transportation to their burner tips because, as a rule, SoCalGas delivered gas for shippers that had firm rights on an upstream interstate system or that purchased gas from shippers having firm rights on an upstream system. Williams Energy Marketing & Trading

[7] Approximately 83 percent of the natural gas California consumes is transported from out of state. "U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply," Energy Information Administration (December 2001), p. 13 (Internet pagination). Thus, traders and customers of natural gas rely principally on out-of-state gas to meet the demands of California users.

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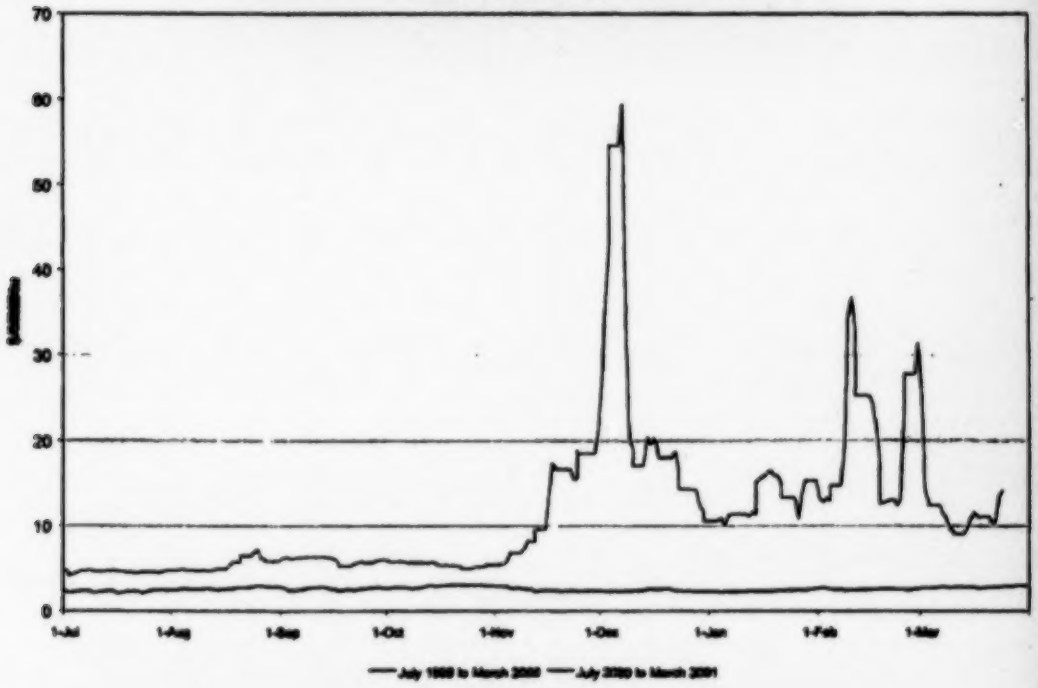
Company is an example of a firm that chose both options: To satisfy contracts to supply generators in southern California, it bought producer gas and shipped it to the border and it also purchased bundled gas at the border. Accordingly, the fact that SoCalGas did not offer firm transportation to generators did not affect the generators' basic option of buying at a production basin and transporting to the border or buying bundled supplies.

Natural gas spot prices at the Southern California Border were historically high in the summer of 2000 and the winter of 2000–2001 (see Figure I-1). For example, the price of natural gas for residential customers in California averaged $12.10/Mcf in January 2001, a 90-percent increase from January 2000.[8]

Figure I-1
Spot Natural Gas Prices at SoCal for the Periods July 1999 – March 2000 and July 2000 – March 2001



Natural gas spot prices at the Southern California Border were also high relative to Henry Hub prices and the prices at other major trading centers. The persistent basis differentials experienced at the Southern California Border, given the presence of transportation that is rate

[8] "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," Energy Information Administration, June 2001, p. 8 (Internet pagination).

regulated by the Commission, suggest a dysfunctional gas market. Table I-1 presents a range of data at various locations.[9]

Table I-1. Various Delivered Natural Gas Prices

Quarter and Year	Henry Hub	Chicago Citygate	Florida Citygate	New York Citygate	SoCal Citygate	PG&E Citygate
3rd quarter 2000	4.47	4.56	5.00	4.81	5.28	5.10
4th quarter 2000	6.41	6.82	6.73	8.07	13.59	12.27
1st quarter 2001	6.44	6.61	6.85	7.83	15.19	10.28

Figure I-2 depicts the radical decoupling of Henry Hub and SoCal average spot natural gas prices on a monthly average basis. Figure I-3 suggests a rough correlation between production basin and SoCal border prices in the period July 1999 through March 2000. Figure I-4 shows production basin and SoCal border prices for the period July 2000 through March 2001. This shows that prices diverged substantially starting in November 2000.

Prices were also high at the northern California border relative to production basin prices (see Figures I-5 and I-6). Part of the reason for this price differential was that gas from the San Juan basin, normally an attractive source of supply for central California, was diverted to the southern California market because of the high prices for spot gas at the Southern California Border. Accordingly, the price at Pacific Gas and Electric Company (PG&E) citygate reflected the fact that the supply from southern California was less than it had been previously. Increased demand also contributed significantly to the high basin differentials in northern California.

[9] "U.S. Natural Gas Markets: Recent Trends and Prospects for the Future," Energy Information Agency, May 2001, p. x; RDI GasDat (for PG&E citygate only).

Figure I-2
Monthly Average Spot Gas Prices at Henry Hub and SoCal

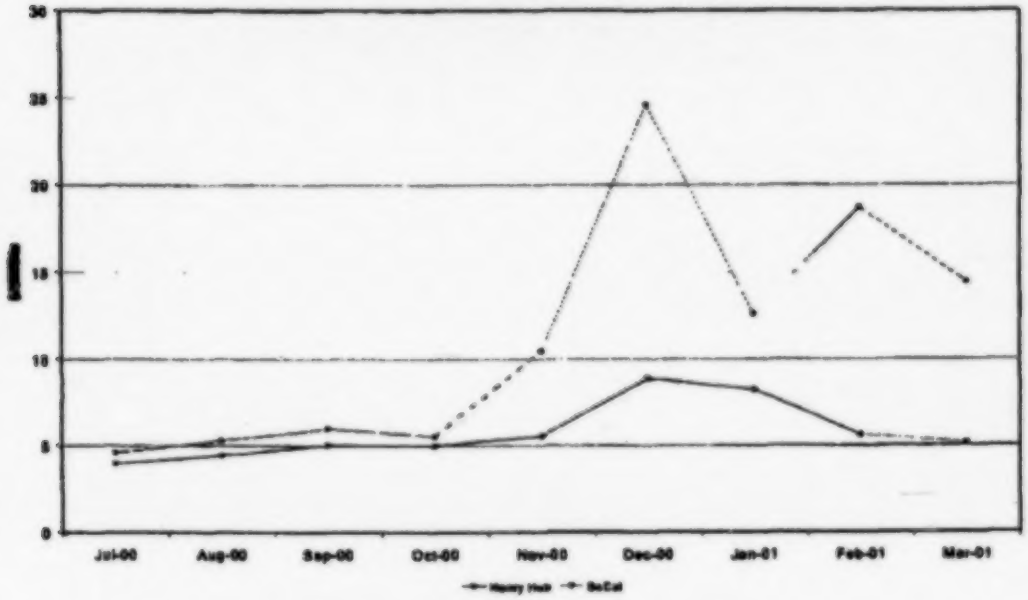


Figure I-3
Daily Spot Natural Gas Prices at Selected Basins and SoCal
July 1999 – March 2000

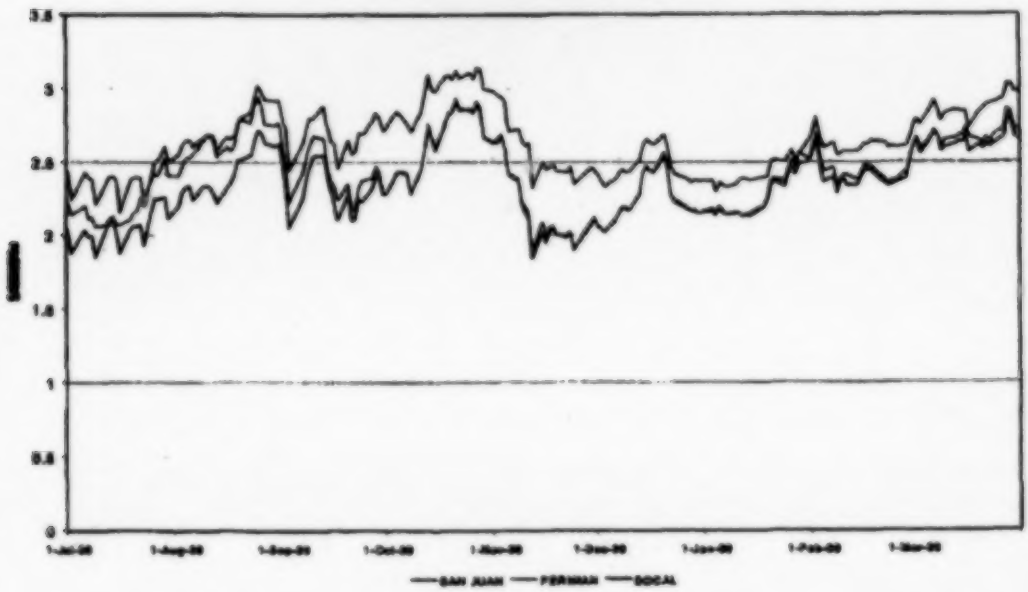


Figure I-4
Daily Gas Prices at Selected Basins and SoCal
July 2000 – March 2001

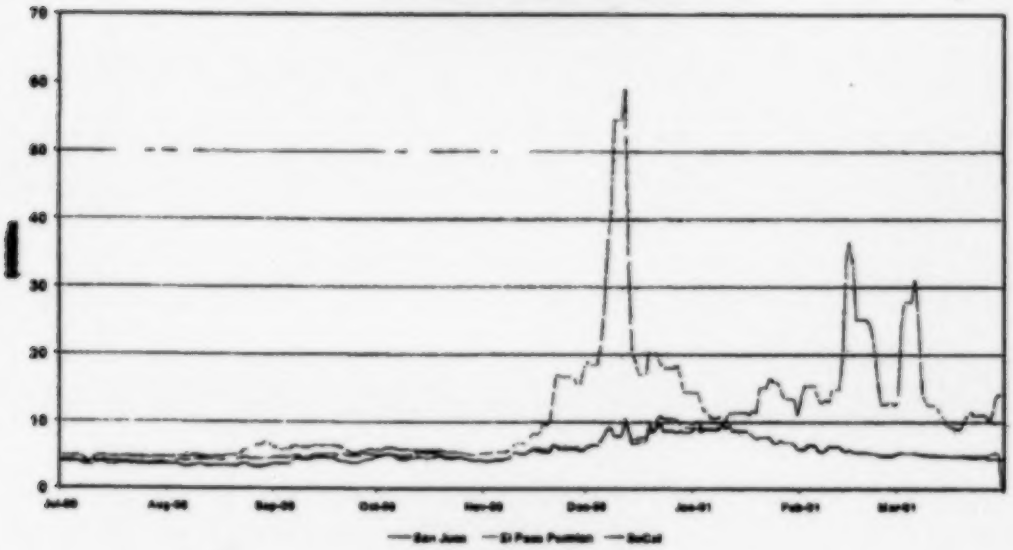


Figure I-5
Daily Natural Spot Gas Prices at Main Canadian Production Point (NOVA (AECO-C)) and PG&E
July 1999 – March 2000

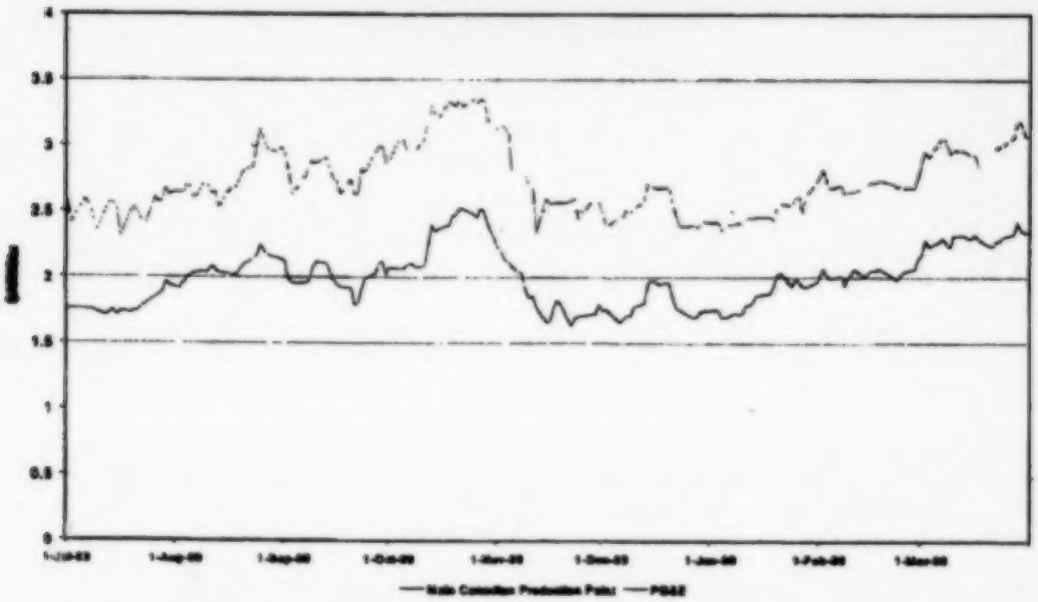
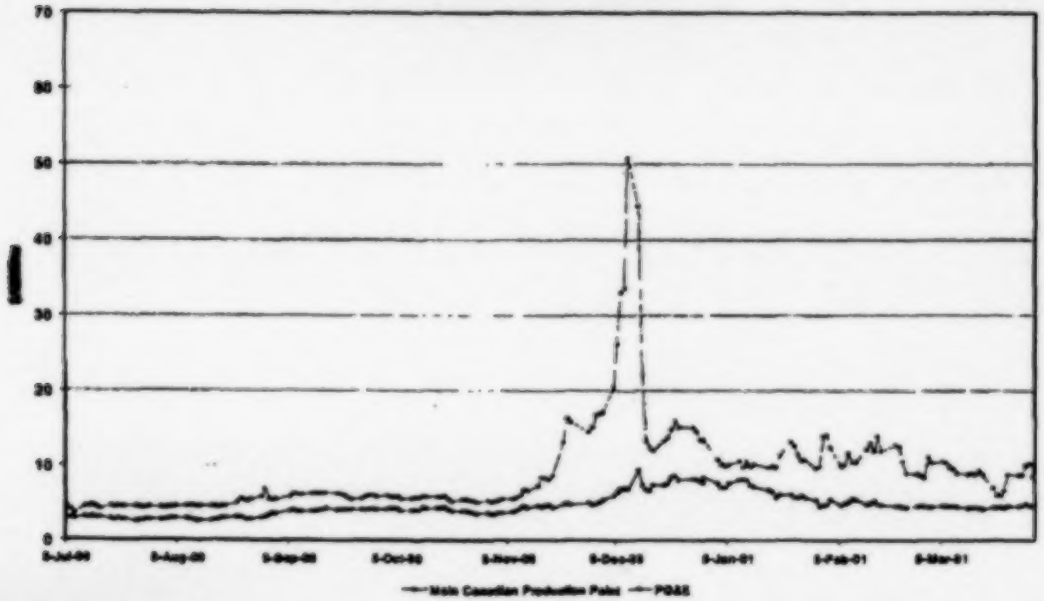


Figure I-6
Daily Spot Natural Gas Prices at Main Canadian Production Point (NOVA (AECO-C)) and PG&E July 2000 – March 2001



Supply/Demand Imbalance and Flawed Market Rules Drove Wholesale Electric Prices Higher During 2000 and 2001

In November 2000, the Commission determined that the electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed in the summer of 2000.[10] This determination stemmed ineluctably from the wholesale prices in California observed during the preceding half-year. This section surveys the major factors that blighted California's wholesale electric markets from the summer of 2000 through the winter of 2000–2001. Overall, the significant increase in power production costs was triggered by increased demand, significant demand inelasticity, and a scarcity of available generation resources throughout much of the West. Further, California's existing market rules exacerbated conditions by exposing the state's three investor-owned utilities to the volatility of the wholesale spot market without affording them the ability to mitigate price volatility and by promoting underscheduling in the PX.

[10]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services (San Diego), 93 FERC ¶ 61,121 at 61,349 (2000).

Weather Extremes and High Demand

The August 2002 Interim Staff Report noted weather extremes and high demand in California during 2000 and 2001.

From June through August 2000, California experienced one of the hottest summers in 106 years of recordkeeping.[11] In November, average temperatures were unusually low. This atypical weather helped drive load growth in California as temperature-sensitive residential customers, in particular, increased their demand. California generators alone produced 414,094 million kWh in 2000, as compared to 383,169 million kWh in 1999.[12]

Reduced snow pack from the winter and lower rainfall in the summer of 2000 reduced western area hydropower output, which California has traditionally relied on to meet its hot-weather peak. Net generation from hydroelectric sources in Washington produced 81 billion kWh in 2000, down from 97 billion kWh in 1999, and net generation from hydroelectric sources in Oregon produced 38 billion kWh in 2000, down from 46 billion kWh in 1999.[13] On a broader scale, hydroelectric generation in the Northwest was 14 percent lower in 2000 than in 1999, which amounts to a reduction of 46.4 million MWh in total Northwest generation.[14] Within California, reduced hydropower availability forced greater reliance on in-state, gas-fired generation, sourced from units that were generally old and relatively inefficient.

Stepped-up demand and low hydropower increased reliance on gas-fired generation, raising the demand for and the price of spot market gas. As one authority summarized, "[b]etween late 2000 and mid-2001 ... a rapid increase in natural gas demand, brought about by a need to increase electricity output from gas-fired power plants (to compensate for decreased availability of hydropower), also created a tight market for natural gas interstate and intrastate pipeline capacity."[15] Noting that "[h]igh electricity prices also reflect reduced Northwest hydropower production due to low rainfall and the generally overstressed state of

[11]Electric Power Annual 2000, Volume I, Preface, Energy Information Administration, p. 6 (Internet pagination).
[12]Net Generation by Census Division and State, 2000 and 1999, Energy Information Administration, p. 2 (Internet pagination).
[13]These were approximately 15-percent declines. Electric Power Annual, Volume I, Preface, Energy Information Administration, p. 10 (Internet pagination). Washington's 1997 hydroelectric generation peaked at 104 billion kWh and Oregon's 1997 hydroelectric generation peaked at 46 billion kWh. Washington and Oregon are California's principal out-of-state sources for hydroelectric power.
[14]"U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply," Energy Information Administration (December 2001), p. 13 (Internet pagination).
[15]"Natural Gas Transportation—Infrastructure Issues and Operational Trends," Energy Information Administration (October 2001), p. 15 (Internet pagination).

the western power grid," one commenter c[illegible]uded that "much costlier natural gas has in turn helped to drive up the operating cost of electric generation."[16]

Sellers of power necessarily relied on older, relatively inefficient units to meet the higher demand or on peaking units that have relatively high running costs. These units were run more frequently, and stressed more, than they had been in the recent past. Consequently, outages of gas-fired units increased in the summer of 2000 in California as compared to the previous summer. These outages reduced the supply necessary to meet demand. Secretary of Energy Richardson cited "a shortage of currently operational electric generation facilities, a shortage of water used to generate electricity, [and] unusual volatility of electricity and natural gas markets" as reasons supporting his finding of an emergency in California "by reason of the shortage of electric energy."[17]

Notwithstanding the increased demand and reduced availability of hydropower, California exported more power to neighboring states in the summer of 2000 than it did in 1999. For example, August 2000 exports averaged 3,136 MW above the August 1999 level. Higher exports reduced that amount of power bid into the day-ahead market. In August 2000, price caps in California were reduced to $250/MW, down from $500/MW in July and early August and $750/MW in June.[18] The lower price caps motivated sales of bulk power at higher prices outside California, where price caps did not apply.

Higher demand intensified transmission congestion, which in turn contributed to higher wholesale electric prices. While on-peak congestion at the California-Oregon border decreased substantially from the summer of 1999 to the summer of 2000, on-peak congestion north to south on Path 15 increased from 1 percent to 7.9 percent and increased from 0 percent to 29.2 percent on Path 26. Off-peak congestion from south to north on Path 15 also increased from 28.1 percent to 49.6 percent.

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[16]Cavanagh, R., "Revisiting 'the Genius of the Marketplace': Cures for the Western Electricity and Natural Gas Crises," *The Electricity Journal* (June 2001), pp. 11 and 13.

[17]Order Pursuant to Section 202(c) of the Federal Power Act, U.S. Department of Energy (December 14, 2000). See also, Order Pursuant to Section 202(c) of the Federal Power Act, U.S. Department of Energy (January 11, 2001) (citing same reasons).

[18]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,121 at 61,353 (2000).

Flawed Market Rules and Regulatory Policies Magnified Adverse Conditions

California's then-prevailing regulatory scheme forbade much forward contracting by the state's three largest investor-owned utilities (IOUs). The three California IOUs were required to purchase power through the PX with little or no ability to purchase through forward contracts, exposing the utilities to the volatility of the spot market without the ability to mitigate that volatility. Even the generation that was not divested by the three California IOUs could not be used directly to self-supply their retail load. Under the California market design, this retained generation had to be bid into the spot market. The California IOUs were required to buy the output of their resources to supply their retail customers. In its December 15, 2000 Order, the Commission eliminated this aspect of the California market design that required that the IOUs must sell all of their generation into, and buy all of their energy from, the California PX.[19]

A second market design flaw was the lack of demand responsiveness. This flaw was exacerbated by a retail rate freeze that insulated residential customers from high wholesale prices, thereby thwarting the ability of price signals to shape and limit demand.

A third major flaw was the underscheduling of load by the three California IOUs. Economic incentives to underschedule tended to increase during high demand periods, which created operational and reliability problems for the Cal ISO and required it to obtain out-of-market energy at high prices. In its December 15, 2000 Order, the Commission established penalties for underscheduling load.

As a result of the conditions and market rules noted above, hourly prices in the PX reached as high as $750/MWh twice in May and eight times in June; average prices were $47/MWh in May, $120/MWh in June, $106/MWh in July, and $166/MWh in August.[20] These prices were vastly higher than year-ago prices. For example, the monthly average unconstrained market-clearing price for May 2000 in the PX's day-ahead market represented a 100-percent increase over May 1999.[21]

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[19]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000).

[20]San Diego, 93 FERC at 61,353 (citing an ISO source); Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of Summer 2000 Price Abnormalities (2000 Western Markets Staff Report), p. 5-1.

[21]San Diego, 93 FERC at 61,353 (citing a PX source).

Finally, emission compliance costs also increased markedly in the summer of 2000. The cost of credits for complying with nitrous oxide standards rose from approximately $6 per pound in May 2000 to $35 per pound in August. Because a combined-cycle gas generator typically emits from 1 to 1.5 pounds of nitrous oxide per MWh, these increased costs were significant.

Gas market rules were also flawed. In particular, the CPUC's rules did not require that storage facilities be filled during the nonpeak season, as discussed in greater detail below. The lack of stored gas in southern California contributed to higher border prices in the winter of 2000–2001.

Transportation Constraints and Spot Market Dysfunctions Contributed Significantly to Higher Spot Market Natural Gas Prices at the California Border

The disparity in prices between the primary production basins that serve southern California, Permian and San Juan, and the spot market price at Topock, Arizona, near the Southern California Border, suggests that natural gas transportation between these points was constrained.

Three major interstate pipelines serve southern California. Table I-2 indicates the limited choices available to gas purchasers for purchasing gas for resale or consumption in southern California.

Table I-2. Interstate Pipeline Design Capacity to California

Pipeline	Design Capacity to California (MMcf/d)
El Paso Natural Gas Company	3,290
Transwestern Pipeline Company	1,090
Kern River	700
Total Design Capacity	5,080

A rupture occurred on El Paso Natural Gas Company's (El Paso's) pipeline in southeast New Mexico in August 2001; capacity was immediately reduced by approximately 1 Bcf/d for about 2 weeks

following the rupture.[22] During the winter of 2000–2001, El Paso operated its pipelines immediately upstream and downstream of the rupture site at reduced pressures pursuant to an Order of the U.S. Department of Transportation.[23] Operation at reduced pressure caused a reduction in El Paso's capacity in the amount of 270 MMcf/d during this time.[24] The loss of capacity was "a major shock to supplies of natural gas in the Western Region, particularly in California, Arizona, and New Mexico."[25] The amount of gas needed to serve 1 million homes is approximately 270 MMcf/d.

High spot prices in southern California were reflected in the willingness of some shippers to pay more than the maximum tariff rate for transportation on pipelines serving southern California.[26] The following table provides a barometer of pipeline capacity scarcity. It shows that shippers were able to release capacity on El Paso's and Transwestern Pipeline Company's (Transwestern's) systems above the maximum tariff rate.[27]

[22]"Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season," Energy Information Administration (October 2000), p. xviii (Internet pagination).

[23]See Corrective Action Order, issued by the Research and Special Programs Administration of the U.S. Department of Transportation, CPF No. 420001004-H (August 23, 2000).

[24]El Paso press release, October 23, 2002.

[25]"Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season," Energy Information Administration (October 2000), p. xviii (Internet pagination).

[26]In Order No. 637, the Commission temporarily removed the rate ceiling for short-term capacity release transactions. The Commission explained that "[d]uring peak demand periods, when capacity is at a premium, the need to provide shippers with the greatest number of potential options and the most efficient competitive marketplace is crucial. Shippers that most need capacity during periods of scarce supply need a market that can efficiently respond to their demands and provide the capacity they need." FERC Stats. & Regs, July 1996 – December 2000 ¶ 31,091 at 31,270 (2000). While this provision of Order No. 637 expired on September 30, 2002, 18 C.F.R. § 284.8(i) (2002), it was effective during the winter of 2000–2001.

[27]San Diego Gas & Electric Company, 95 FERC ¶ 61,264 (2001) (Appendix).

Table I-3. Capacity Releases Above the Maximum Tariff Rate

Month	Pipeline	Amount Released Above Maximum Rate (MMBtu/d)[28]
November 2000	El Paso	33,800
December 2000	El Paso	7,000
January 2001	El Paso	12,500
January 2001	Transwestern	7,766
February 2001	El Paso	19,269
March 2001	El Paso	34,566

As the Commission pointed out in an order addressing the data in Table I-3, the volumes of released capacity above the maximum tariff were not large relative to the total capacity serving California.[29] Nonetheless, the data provide an indication of the persistence of capacity scarcity because they show that some shippers were willing to pay above-tariff prices to avoid paying high bundled prices at the California border. The volumes of released capacity may have been relatively low, not because a market for capacity above the maximum tariff rate did not exist, but because shippers holding capacity wanted to use it themselves to transport gas to the California border rather than release that capacity to other shippers.

In short, demand for interstate pipeline capacity and capacity from the border into California exceeded supply. Border prices would not have exceeded production basin prices as dramatically as they did had there been sufficient transportation capacity to meet all of the gas demanded by customers in southern California.

Low storage levels contributed to higher prices and greater volatility in the gas market in southern California. If the CPUC rules required that storage facilities be filled, gas supplies would have been increased during the winter of 2000–2001. Shippers use storage during peak periods to supplement interstate pipeline deliveries. Storage levels were historically low approaching and during the winter of 2000–2001. California began the 2000–2001 winter season with 152 Bcf in storage, which was 34 Bcf below the 5-year (1995–1999) average.[30] By mid-February 2001, California's working gas inventories were estimated at less than 70 Bcf, as compared to the 1995–1999 average of 100 Bcf for the end of March.[31]

[28] An MMBtu is roughly equal to an Mcf.

[29] San Diego, 95 FERC at 61,934-935.

[30] "U.S. Natural Gas Markets: Recent Trends and Prospects for the Future," Energy Information Agency, May 2001, p. 22.

[31] "U.S. Natural Gas Markets: Recent Trends and Prospects for the Future," Energy Information Agency, May 2001, p. 23.

Storage levels were low for several reasons. First, the Carlsbad rupture caused shippers to draw down storage inventories in August that would otherwise have been available for the winter heating season.[32] Second, natural gas prices above the historical average in southern California in the summer of 2000 caused market participants to reduce the amount of gas they put in storage. These market participants believed that gas prices would moderate, permitting them to fill storage later in the season or purchase natural gas on the spot market at lower prices.[33]

Additional factors, including higher gas-fired generation output due to low hydropower availability, nuclear plant outages in November 2000, and unusually cold temperatures in November 2000, contributed to the drawdown of storage serving southern California customers.[34]

Many of the market participants that sold natural gas at the Southern California Border during the winter of 2000–2001 were trading companies that engaged in major business activities outside of California. However, handwritten daily transaction sheets that Southern California Gas Company (SoCalGas), a local distribution company,[35] provides each month to the CPUC indicate that SoCalGas profited significantly from border sales at elevated prices. These records show, for example, that for the flow date December 12, 2000, a date on which natural gas prices at the California border were extraordinarily high, SoCalGas purchased gas for approximately $11 from production area sources and sold gas at Topock for as much as $65. For the flow dates February 10 through 12, 2001, the days preceding a run-up of border prices, SoCalGas purchased gas at an average price of less than $14. From February 14 through 16, when gas prices were spiking, SoCalGas sold gas at an average price that exceeded $30. SoCalGas' ability to store gas suggests the potential for substantial earnings stemming from these transactions. Under a performance-based rates program authorized by the CPUC, a portion of profits derived from trading activity would have been realized by shareholders of SoCalGas' parent company. For the period October

[32]"U.S. Natural Gas Markets: Recent Trends and Prospects for the Future," Energy Information Agency, May 2001, p. 14.

[33]This is suggested in part by data for nationwide futures prices for natural gas. "Natural Gas Winter Outlook 2000–2001," Energy Information Administration, *Natural Gas Monthly*, October 2000, p. xxiii.

[34]"U.S. Natural Gas Markets: Recent Trends and Prospects for the Future," Energy Information Agency, May 2001, p. 23. Staff Report to the Federal Energy Regulatory Commission on Northwest Power Markets in November and December 2000, February 1, 2001, pp. 21-22.

[35]SoCalGas, whose facilities are located solely within the state of California, is a so-called "Hinshaw" pipeline that is exempt from the Commission's jurisdiction under section 1(c) of the Natural Gas Act, 15 U.S.C. 717(c) (1994).

2000 through March 2001, SoCalGas purchased approximately 56,816,000 MMcf for a total of approximately $626,900,000, or $11.04/MMcf, and sold at wholesale 12,856,000 MMcf for $213,640,000, or $16.60/MMcf. These data show that SoCalGas benefited from higher bundled prices and general volatility during this period. Taken as a whole, SoCalGas' trading activity indicates that profiteers included at least one market participant subject to California's regulatory oversight.

Staff concludes that transportation constraints and spot market dysfunctions contributed significantly to high spot gas prices and that this justifies the substitution of a new methodology for calculating electric prices for this period of market dysfunction that the Staff proposed in Chapter IV.

Market Manipulations Significantly Influenced Reported Spot Prices for Natural Gas in California

The reasons discussed thus far that impeded spot market natural gas prices from adhering to historical norms—supply/demand imbalance, inefficient market rules, and transportation constraints—may be attributed to the intertwining strands of poor market design, ill-timed market conduct, and fortuity. However, two specific activities, (1) trading in anomalous patterns at Topock and (2) false reporting of market transactions to publications for compilation in price indices, reflect deliberate conduct to manipulate market outcomes. These manipulations significantly influenced reported spot prices for natural gas, heaping further aggravation on the already stressed spot market. Because a substantial volume of spot market gas was purchased to fuel electric generation plants in California, the manipulations directly contributed to higher bids by sellers of wholesale power into the PX and ISO spot market and consequently to higher payments made to these sellers. The manipulations of anomalous trading and false reporting fatally undermine published price indices as reliable measures of market activity in a well-functioning market.

Trading in Anomalous Patterns at Topock

Topock is a major delivery point at the junction of El Paso Natural Gas Company's interstate pipeline and Southern California Gas Company's intrastate pipeline. Topock is particularly significant as a trading point because EOL traded gas at this point, which attracted a substantial volume of activity. An analysis of trading data shows that the activity of a single firm's (Reliant Energy Services, Inc. (Reliant))

gas trading significantly influenced spot prices at Topock. The data also show that Reliant benefited from exerting influence on spot prices. Reliant's trading increased spot market natural gas prices on average by about $8.54/MMBtu in December 2000 and by about $1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant's churning. We explain and document this conclusion in the following section.

False Reporting of Market Transactions to Publications

Evidence continues to accumulate that natural gas trading entities provided false reports to periodicals that published price indices.[36] The epidemic of false reporting affected the accuracy of spot prices, including the California burden prices used in the Commission's California refund calculation. While widespread false reporting vitiates the utility of published price indices as a reliable measure of market activity, it has other important implications as well. First, valuation of forward contracts and other price-sensitive instruments is dependent in part on published price indices. Natural gas futures traders use published indices to enter contracts and assess risks. Second, spot prices affected by false reporting affect next-day spot prices, thus impacting the physical market as well. Third, false reporting undermines investor confidence in the ability of the physical gas market to operate successfully.[37] We explain and document our conclusions regarding the extent and impact of false reporting in Chapter III.

[36]For example, on December 18, 2002, the Commodity Futures Trading Commission (CFTC) imposed a $5 million penalty against Dynegy Marketing and Trade (Dynegy). "Order Instituting Proceedings Pursuant To Section 6(c) and 6(d) of the Commodity Exchange Act, Making Findings and Imposing Remedial Sanctions," CFTC Docket No. 03-03 (December 18, 2002). In its order, the CFTC determined that from 2000 through June 2002, Dynegy knowingly reported false natural gas price and volume information to certain reporting firms in an attempt to skew gas indices relative to various hubs in the United States to Dynegy's financial benefit. As another example, El Paso Corporation acknowledged on December 4, 2002, that Todd Geiger, a vice president at its El Paso Merchant Energy unit, was charged by Federal authorities with knowingly providing inaccurate gas price data to a trade publication. The false trade data were allegedly provided for transactions at Sumas, on the United States-Canada border.

[37]Credit has largely evaporated, or become very expensive, for power trading companies in the wake of Enron Corporation's collapse and disclosures elsewhere in the sector. In the past year, Allegheny Energy, Inc., American Electric Power, Progress Energy, Inc., and Williams Companies, Inc., among others, have scaled back their trading and Aquila, Inc., CMS Energy Corp., Dynegy, Inc., and El Paso Corporation, among others, have exited trading. "U.S. Utilities Retreating From Energy Trading," Reuters, January 8, 2003.

II. Analysis of Gas Trading Activity in Southern California

Summary

In this chapter we conclude that Reliant Energy Services (Reliant) engaged in a high-volume, rapid-fire trading strategy to purchase its physical spot gas needs at Topock. Reliant often bought and sold many times its needs in quick bursts, which significantly increased the price of gas in that market. We describe this as "churning" and define its characteristics later in this chapter. We use this term even though it has other connotations in securities or futures trading because it gives the best visual image of Reliant's behavior. Reliant's churning enabled it to reduce the overall cost of the gas it actually needed. Through its churning, Reliant profited by selling gas at or near the top of the price climb it caused. Reliant was often such a large presence at Topock that its trading strategy moved the entire market price. Our analysis shows that the price of gas would have been lower by about $8.54/MMBtu in December 2000 and by about $1.69/MMBtu over the 9 months of the California Refund Proceeding absent Reliant's churning. These inflated gas prices have been used in the California Refund Proceeding to set the prices that clear the entire electric spot market. This greatly magnifies the effect of Reliant's actions upon gas prices.

Staff concludes that these gas prices are not the result of competitive conditions and would not produce just and reasonable electric prices in the California Refund Proceeding. Later in this Report, we recommend alternative gas prices for the Commission's consideration. We also recommend amending the Commission's blanket certificates to establish guidelines for trading natural gas as well as reporting and monitoring requirements.

Background

During the winter of 2000–2001, the southern California natural gas market experienced high prices, large price swings, and high volumes. Based on findings in the Staff's Interim Report, we made a detailed investigation of trading activity in the market during this period, focusing on trading on the EnronOnline (EOL) trading platform. We examined trading for all gas products traded on EOL, traded by any counterparty, and traded across all western locations, including both citygate locations as well as basins. We examined trading for spot gas, longer term physical gas transactions, and financial gas products. We found unusual trading patterns associated with Reliant transactions on

the EOL trading platform. Staff, with the assistance of Professor Robert S. Pindyck of MIT and Michael Quinn of Analysis Group/Economics, conducted an investigation into these activities.[1] The results of this analysis are the subject of this chapter.

The firms, individuals, and trading practices highlighted in this chapter contributed to uncertainty and price volatility in gas markets, and ultimately in electricity markets as well. In particular:

- Analysis of trading data shows that there was often so little liquidity at Topock that Reliant's gas trading significantly influenced spot gas prices at that location.
- This in turn significantly influenced index prices, which were used to set the market-clearing price in the California Refund Proceeding.
- Reliant's trading increased spot market gas prices significantly, on average over $8.54 MMBtu for December 2000.

This chapter examines natural gas trading in southern California from November 2000 through June 2001, focusing on Reliant's activity on the EOL trading platform and on the Topock[2] location. This is a key point for defining published natural gas price indexes. We provide an in-depth descriptive analysis of Reliant's trading activities, both in terms of actual trades executed and the trading staff, operations, and processes in place. This analysis shows that whenever the market exhibited anomalous patterns (e.g., high prices, price swings, high gross volumes traded), Reliant was typically the most active trader by a variety of measures.

Our analysis also reveals that Reliant's trading activity involved a great deal of churning, i.e., the repeated buying and selling of

[1]Robert S. Pindyck is Bank of Tokyo-Mitsubishi Professor of Economics and Finance at MIT's Sloan School of Management. Professor Pindyck is a nationally recognized econometrician with a specialty in energy futures markets. Michael Quinn is a vice president with Analysis Group/Economics. He has a doctorate in Economics from Princeton University. Dr. Quinn specializes in the application of economics to issues in the natural gas and electricity industry, and he has served as an expert on matters involving natural gas transportation and distribution.

[2]The El Paso Natural Gas pipeline terminates at the California-Arizona border. The two interstate crossings from Arizona into California are at a northern corridor crossing between Topock, Arizona and Needles, California (where El Paso connects to the intrastate systems of both Southern California Gas Company and Pacific Gas and Electric) and at a more southern crossing between Blythe, California and Ehrenberg, Arizona (where El Paso connects to the intrastate system of SoCalGas).

substantial quantities of physical spot gas in a short period of time.[3] Reliant's churning generally occurred on trading days during which prices changed significantly—particularly in December 2000. We use econometric analyses to demonstrate the impact of churning on price levels and to estimate counterfactual prices, i.e., the prices that would have prevailed in the absence of Reliant's churning activity.

We also examine the relationship between Reliant's physical trading and financial trading and positions on key dates to determine the extent to which Reliant's financial trading activities may have benefited from its physical trading activities. Disaggregating and analyzing trading data for individual financial traders reveals that the trades of one particular Reliant physical trader benefited Reliant over $18 million from its financial positions due to its churning.

Descriptive Analysis

Our analysis of EOL trading activity revealed that anomalous trading patterns occurred under the following circumstances:

- At Topock, a key pricing location for natural gas and, in turn, electricity in California.
- For next-day gas flow, the product used for the published spot market index prices that affected both gas and electricity prices in California.
- During the refund period.
- In Enron's trading with Reliant in proportions far greater than with other counterparties.
- With the same Reliant trader.

Most notable among these anomalies is the extent to which Reliant's trading activity involved churning through the execution of a large number of trades in both directions (both buys and sells) in a short amount of time—numerous rapid buys and numerous rapid sells. The Reliant trader of physical spot market gas at the California-Arizona border, for entry into the system of Southern California Gas Company

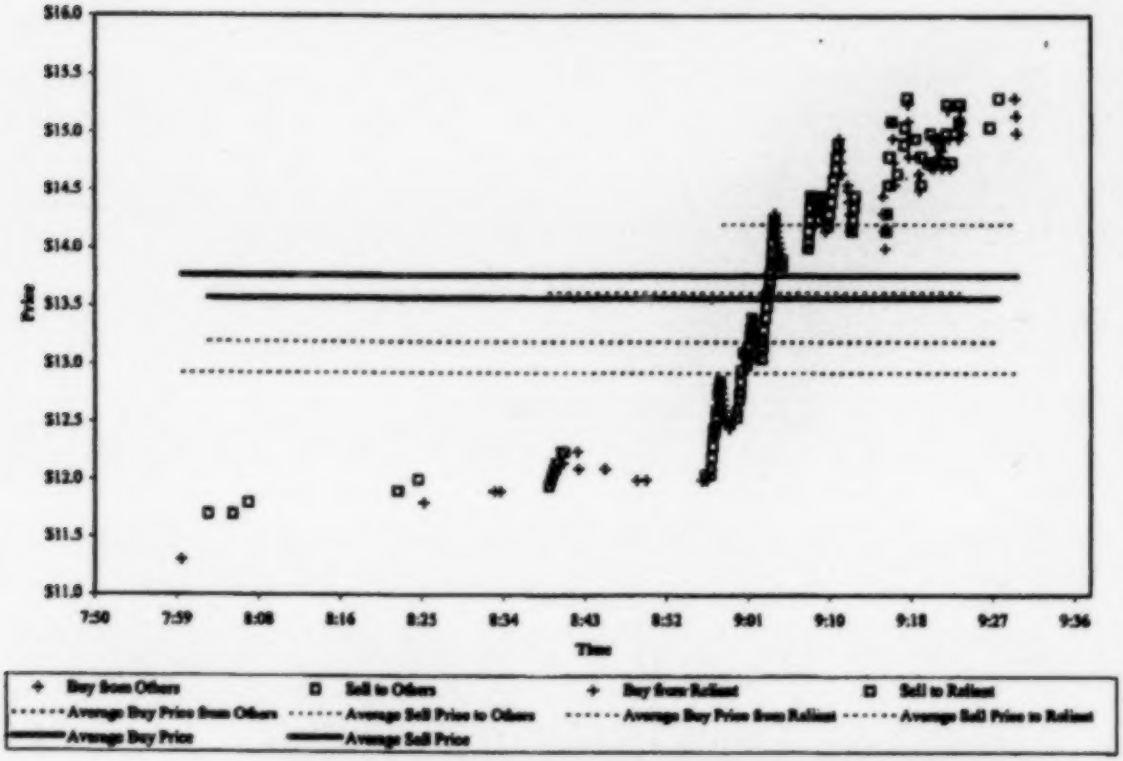
[3]For the purposes of this report, "churn trading" describes a pattern of gas purchases and sales where: (1) a particular company both buys and sells during the trading interval, so that the company's gross trading volume greatly exceeds its net trading volume; and (2) the company makes a relatively large number of consecutive purchases (or sales) in a short amount of time, often being the only buyer (or seller) during the burst of transactions.

(SoCalGas,[4] a Sempra company), would frequently buy and sell large quantities of gas within the (at most) 90-minute trading day, finishing with a net position much smaller than gross volume. The most extreme example is the trading activity of January 31 for flow on February 1 (highlighted in the Initial Report). On that day, Reliant bought 1,010,000 MMBtu of gas and sold 730,000 MMBtu, for a net purchase of 280,000 MMBtu. To achieve this, the Reliant trader entered into transactions at the rate of one every 10 seconds over the course of 30 minutes, producing sharp price movements on EOL that all traders would see without knowing the cause. We did not observe any other firm trading in this manner—either in terms of churning buys and sells or rapidly executing a large number of trades.

Figure II-1 depicts trading on Wednesday, January 31, 2001, for gas flow at Topock on February 1, 2001. On this day, 227 trades took place on EOL; more than 75 percent of them were transactions between Reliant and Enron. Each of the 101 blue squares in the figure is a purchase from Enron made by Reliant on EOL. Each of the 73 red crosses is a Reliant sale to Enron. The other 53 trades are between Enron and other counterparties. The first transaction, at 8:00 a.m., is an Enron purchase of 10,000 MMBtu at $11.30/MMBtu. The last transaction, at 9:30 a.m., is a sale of 10,000 MMBtu from Reliant to Enron for $15/MMBtu. The grey horizontal line is Enron's average purchase price for the day, and the green line beneath it is Enron's average sale price. Enron loses money for the day trading Topock spot gas. The dotted red line is Reliant's average sale price to Enron, and the dotted blue line beneath it is Reliant's average buy price from Enron. Prices rise slightly during the first hour of trading, from $11.30 to $12. Once Reliant begins actively churning, the price rises quickly and steadily, peaking at $15.30 and closing $3.70 higher than the price at which it opened.

[4]Throughout this chapter, "SoCalGas" refers to the Southern California Gas Company and "SoCal" refers to gas at the California-Arizona border for entry into the system of SoCalGas.

Figure II-1
Day-Ahead Trades at SoCal
January 31, 2001 for February 1, 2001 Gas

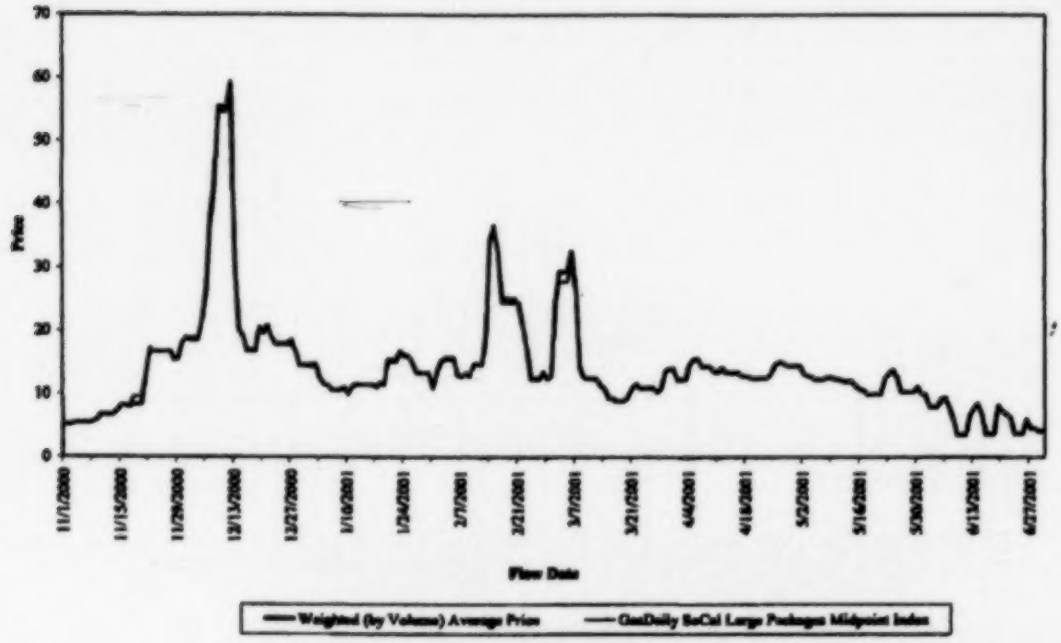


Trading patterns such as those on January 31, 2001 took place a number of times. From an initial review of these trading patterns, it appeared possible that Reliant's trading with Enron may have increased prices, price volatility, and price uncertainty in the entire southern California gas market. That is, Reliant's trading practices with Enron may have caused Enron to change the prices at which it was offering to buy or sell gas at any given time. In contrast, a typical bilateral gas trade—not taking place on EOL—would not necessarily affect the prices at which Enron offered to buy or sell, and thus would not be seen by the whole market as the new market price because the terms of bilateral gas transactions are generally held confidential between the two parties. The public nature of EOL prices is a key factor.

EOL prices closely tracked the reported index prices. Figure II-2 charts spot gas prices at the California border as traded on EOL (Topock and Ehrenberg) and as reported by *Gas Daily*. The correlation

between average EOL prices and the *Gas Daily* midpoint price for SoCal was 0.999 from November 2000 through June 2001.

Figure II-2
EOL Average Price vs. *Gas Daily* Midpoint Price at SoCal
November 2000 – June 2001



Further investigation into Reliant's risk management, operational, and trading practices uncovered the following key facts:

- Reliant's primary SoCal[5] physical spot market trader worked alone in Los Angeles, while the rest of Reliant's traders worked together in Houston.
- The physical spot trading activities of this one trader were affected significantly by a "netting" agreement (described below) that provided a financial incentive to churn, and that would not have been meaningful had there not been "cuts" on El Paso.[6]
- For its own power plants' needs, Reliant bought large quantities of gas in the spot market for many days during the refund period, most of it at the constrained Topock point.

[5]The trader dealt in gas for flow on the SoCalGas system.
[6]Throughout this time period, shippers on El Paso's system frequently did not receive their full nomination of capacity, but were instead cut to some lower amount. Among interstate pipelines, El Paso stands out in terms of the frequency of cuts.

- The pricing and load forecasting provisions in Reliant's contract with the Los Angeles Department of Water and Power's (LADWP's) nomination practices, and Reliant's risk management practices, all encouraged Reliant to buy spot market gas.

Churn Trading and Netting Arrangement

Reliant and others had a netting arrangement with Enron for dealing with SoCal trades between them. The frequent cuts of nominations from El Paso into SoCalGas's system created potential problems for customers such as Reliant, problems that did not exist when such cuts did not take place. In particular, a customer selling gas might receive cuts in its nominations from El Paso, and such a seller might then cut its counterparties in order of price. This practice is sometimes referred to colloquially as "price majeure." Accordingly, receiving a lower price on a specific transaction might bring with it a lower probability of flow. This concern was especially important to Reliant because it was such a large buyer in the spot market.

The netting arrangement worked as follows: All of Reliant's purchases from Enron were taken together to form a volume-weighted average price. All Reliant sales to Enron were combined in the same way. When there were both sales and purchases, the matching amounts were first netted out against each other and the balance was then settled at the respective average prices. Therefore, the lower-priced transactions were not cut disproportionately. In addition, when there were both sales and purchases, the offsetting or matching amounts would be netted against each other and settled first. Reliant could retain any net profit from the sales even though it was a net buyer and actually owed Enron money overall.

The netting arrangement is not completely transparent. However, as we demonstrate later, whenever Reliant was a net buyer, the netting arrangement gave Reliant a financial incentive to churn. For the period November 2000 to June 2001, Reliant's total profit from the netting agreement was $8.9 million; the majority of the profit ($7.3 million) came on days in which Reliant churned.

The highest priced day in market history, December 11, 2000 for December 12 flow, was also the day of the highest profits from netting. Reliant lost money from netting on only 3 of the 24 churn days, and the total amount of losses was less than $30,000. In contrast, the netting arrangement resulted in a number of days of significant upside for Reliant. Reliant's profits from netting were approximately

$5 million for December. Virtually all of these profits were in the first 8 days of trading, when market prices rose to all-time highs.

Econometric Analysis

An econometric analysis of the effect of Reliant's trading on market prices showed the following:

- A clear, robust, and statistically significant relationship—controlling for other factors—between Reliant's churning and prices rising.
- The price rise generally persisted for a few days before ultimately dissipating.
- Gas prices in southern California were, on average, more than $8.54 MMBtu/d higher in December 2000 than they would have been absent Reliant's EOL trading activity.

Reliant was a large and consistent spot gas buyer for both its own needs and those of LADWP. In this regard, Reliant was unlike most of the other firms buying and selling gas for the SoCal area. Reliant's frequent need for large amounts of spot gas, and its lack of storage, may have affected its approach to trading, as Reliant was at risk for the market discovering that Reliant needed a lot of gas on a particular day.

Staff struggled with whether Reliant's trading activities were affected by the level of transparency on EOL, whether some of Reliant's behavior could have been attributed to price discovery, and that Reliant may have been merely "riding the market" and simply profiting from that ride. Such an explanation, however, would have us overlook the enormous share of trading Reliant comprised on many days, the rapid-fire manner in which Reliant frequently bought gas, and the resultant price increases. The volumes and trading pattern simply do not lend themselves to testing the waters for price discovery. Nonetheless, it is possible that prices would have risen by some amount on at least some of the days when Reliant churned, even if it had not churned.

Our econometric analysis clearly establishes a correlation between Reliant's churn trading and higher gas prices. What it does not do—and cannot do by itself—is prove causation. In addressing causation, Staff took into account all of the available information, of which the econometric analysis is but one component. The fact that no other company remotely approached Reliant's size, Reliant's trading

strategy, and the markedly different market behavior on days when Reliant did not churn are all important considerations. When viewed in total, the evidence supports a conclusion that churning caused prices to rise.

Linkages Between Physical and Financial Trading

The investigation for linkages between Reliant's physical and financial trading indicated:

- Reliant was an active trader of financial gas derivative products in southern California, trading SoCal basis swaps and SoCal balance-of-month "swing" swaps throughout the refund period.[7]
- One Reliant financial trader made profits of $23.4 million from December SoCal swaps purchased on November 30, 2000. After this transaction, Reliant's trader of physical spot market gas at the same location then churned for 8 consecutive trading days.
- About $18 million of the profits from these financial trades resulted from Reliant's churning.

Investigation of Reliant Trading

The Initial Report[8] stated that certain gas trading patterns on EOL would be investigated further because a preliminary examination of physical spot gas transactions on EOL identified anomalous trading patterns, in particular with respect to Reliant's trading with Enron.[9]

While it would be imprecise to describe any individual day during this time period as "typical," we present a few summary statistics on average EOL trading levels for SoCal (Topock/Ehrenberg) during the

[7] In a gas "swap," two counterparties execute a trade in which the buyer pays a fixed, known price for some notional quantity of gas and the seller pays a price that will vary with the market price, which will only be known later. Thus, the buyer in a swap transaction is going long and is betting that prices will rise. The seller is betting that prices will fall. These transactions are settled financially, involving no gas delivery. The two types of swaps that we examined are explained below.

[8] *Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-000, prepared by the Staff of the Federal Energy Regulatory Commission, August 2002, pp. 49-51.

[9] The Initial Report did not name Reliant, but referred to it as an unidentified "single counterparty."

period from November 2000 to June 2001. On average, 78 SoCal spot trades per day took place. Of these, 27 were with Reliant and 51 were with all other firms combined. On average, Reliant bought (net) 144,000 MMBtu/d from Enron during this time period, while all other counterparties combined to sell (net) Enron 250,000 MMBtu/d. The *combined* gross trading of counterparties other than Reliant exceeded their net by 70,000 MMBtu/d. Reliant's gross trading exceeded its net trading by more than 100,000 MMBtu/d.

Examples of anomalous trading patterns include:

- On dozens of occasions, these 2 counterparties traded with each other more than 20 times (up to 174 times) within the (at most) 90-minute trading day. No other firm traded with Enron in this way, either in terms of number of trades or the rate at which transactions would take place. Appendix II-A provides a number of tables, as described below, highlighting Reliant's trading activity on EOL.
- Reliant was by far the firm most likely to engage in consecutive trades for spot contracts on the EOL system. During one timeframe on January 31, 2001, Reliant made 43 consecutive trades before another firm conducted a trade. Reliant was the only firm to make more than 13 consecutive trades and was the counterparty for 34 of the 40 longest streaks of consecutive trades.
- Reliant initiated transactions with Enron in bursts unmatched by other counterparties. From November 1, 2000 through June 2001, only once did another firm conduct as many as 10 trades at a single location within a "clock minute" (e.g., 8:51:00 a.m. to 8:51:59 a.m.); Reliant did this 14 times, and was the top trader for 38 of the 40 busiest minutes.
- Spot market trading for next-day flow from El Paso Natural Gas into SoCalGas at Topock, Arizona, showed unusual activity between Enron and Reliant. As the Initial Report indicated:[10] (1) Topock spot market prices are of particular interest because of their impact on actual prices paid for gas and electricity and (2) EOL prices closely tracked reported index prices.

Staff found these patterns troubling because it appeared that Reliant's trading with Enron may have increased prices, price volatility, and price uncertainty to the entire southern California gas market. The market would see the effects of the transactions' pricing through a change in the prices at which Enron would offer to buy and sell gas without knowing that only one trader was causing the change. In contrast, a typical bilateral gas trade—not taking place on EOL—would not be seen by the whole market as the new market price, since

[10]Initial Report, pp. 52-55.

the terms of bilateral gas transactions are generally held confidential between the two parties. The public nature of EOL prices is a key factor.

Accordingly, we analyzed in detail:

1. EOL trading activity of gas for delivery into the SoCalGas system, both for physical gas and for financially settled gas derivative transactions that were based on SoCal prices (swaps and basis swaps).
2. Trading activity between Enron and Reliant for Topock spot market gas and for all other western transactions, both physical and financial.
3. Trading activity of the individual traders involved in the anomalous trades.
4. Trading activity of Reliant with all counterparties.

Exploratory Descriptive Analysis

Preliminary analyses examined EOL trading records for 2000 and 2001.[11] Staff subsequently narrowed the focus to the period November 2000 to June 2001 for specific analyses (described below). These analyses revealed the unique characteristics of spot trading in southern California and Reliant's trading in particular. The following was determined: the "products" that were most actively traded, the types of prices at which the transactions took place, and the geographic locations where trading was the most active.

By and large, spot gas was the most heavily traded product across all locations. On EOL, spot gas transactions took place at fixed (rather than indexed) prices, and are the types of transactions that allegedly are used for producing the reported daily spot market index prices published by *Gas Daily*, *Natural Gas Intelligence* (NGI), and *Inside FERC*. These daily spot market index prices are used in physical gas contracts tied to indexes and for settling many financial derivative products, such as balance-of-month swing swaps (defined and discussed further below).

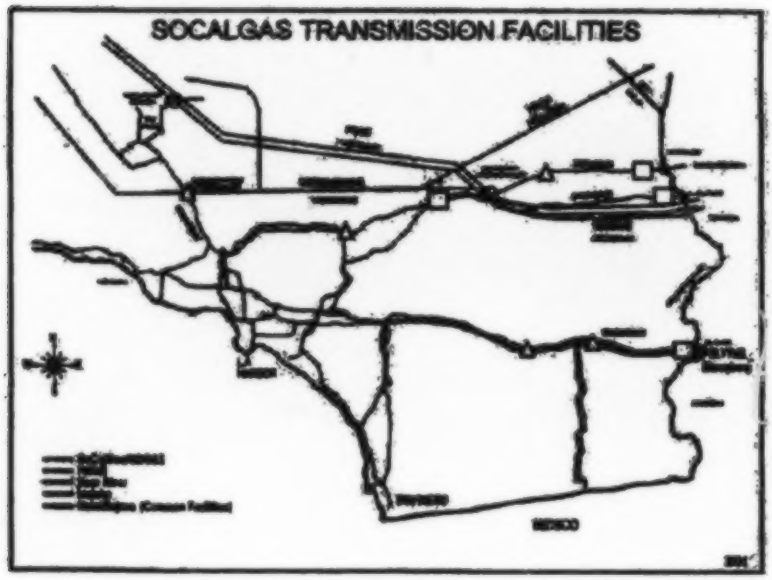
Among the various geographic locations, the California-Arizona border for entry into the SoCalGas system was the most actively traded. On EOL, of the entry points into SoCalGas, Enron offered only Topock until March 2001, when it added Ehrenberg. Another 750,000

[11]The EOL data we have comprise all physical and financial trades transacted on EOL for the period February 7, 2000 through June 29, 2001 for the western part of the United States. Data for January 2000 are incomplete.

MMBtu/d could enter the SoCalGas system at the terminus of the Transwestern pipeline (at Needles, California). Within California, gas was also traded at Hector Road (the interconnection of Mojave, SoCalGas, and PG&E) and Wheeler Ridge (the interconnection of Kern River and SoCalGas). However, none of these locations were traded on EOL.

The fact that Enron traded only at Topock during December 2000, for example, meant that someone who wanted to buy gas on EOL and deliver it into the SoCalGas system was limited to the constrained Topock location. Only 540,000 MMBtu/d could enter the SoCalGas system at Topock.[12] Another 1,210,000 MMBtu/d could enter at Ehrenberg and Needles. Accordingly, restricting one's trading to Topock could have been a significant limitation.

Figure II-3



[12]Throughout this chapter, volumetric measures of gas pipeline capacity are reported in terms of MMBtus, using an approximation of 1 MMBtu = 1 Mcf.

The bulk of our EOL trading analysis focuses on spot gas traded at the California-Arizona border. Spot market, or swing, gas is typically traded 1 day ahead of its flow date.[13] For weekends and holidays, gas on EOL was traded in a multiday package—e.g., on Friday a buyer purchases gas for flow on each of Saturday, Sunday, and Monday.

Reliant's SoCalGas Trading on EnronOnline Stands Out

Looking across all western locations where spot market gas was traded on EOL, the volume of gas traded by Reliant with Enron, at Topock in particular, is quite prominent.

Table II-1 covers the period November 1, 2000 through June 2001 and sums the volume of western physical spot market trading activity for the top 15 Enron counterparties on EOL. As the table shows, Reliant had the largest gross trading volumes for all locations combined, and Reliant's Topock volumes alone are more than the second largest counterparty's (Duke) combined EOL activity across all locations. In the EOL data, Topock was also the most active location for El Paso, Dynegy, Aquila, and Williams, in addition to Reliant.

Reliant's head of gas trading explained that Reliant had a risk management policy of buying forward gas to match forward power contracts and relying strictly on spot gas for spot electric sales. Because it was almost entirely in the spot electric market, Reliant relied heavily on spot gas.

[13]Monthly (or longer term) "baseload" gas is a different product. Baseload gas prices are set based on trading in the last week of the month prior to the month of gas flow. For example, "March gas" is priced based on trades during the last week of February. A quantity of March gas, such as 10,000 MMBtu/d, involves the delivery of 10,000 MMBtu each day from seller to buyer.

Table II-1. Top 15 Counterparties by Gross Volume and Top Locations by Gross Volume (EOL, November 1, 2000 – June 30, 2001)

Top 15 Counterparties			Top Locations		
Counterparty	Number of Transactions in All Locations	Gross Volume	Location	Number of Transactions in Location	Gross Volume in Location
Reliant Energy Services, Inc.	4,870	64,366,219	SoCal Topock EPNG	3,412	48,103,388
Duke Energy Trading and Marketing, L.L.C.	3,408	37,245,838	PG&E Clygte Pool	1,491	18,171,475
El Paso Merchant Energy, L.P.	2,847	29,879,471	SoCal Topock EPNG	668	8,910,324
Dynegy Marketing and Trade	2,458	25,053,501	SoCal Topock EPNG	695	9,534,971
Aquila Energy Marketing Corporation	2,224	22,983,237	SoCal Topock EPNG	585	7,969,234
Enserco Energy, Inc.	2,819	20,787,593	Opal	978	6,965,285
Cook Inlet Energy Supply L.L.C.	2,370	19,891,233	Opal	1,318	10,113,500
BP Energy Company	1,993	16,841,184	Opal	700	5,088,092
Coral Energy Resources, L.P.	1,816	16,648,171	PGT Malin	494	4,481,224
Mirant Americas Energy Marketing, L.P.	1,509	14,103,077	PG&E Clygte Pool	464	4,664,951
Sempra Energy Trading Corp.	1,288	11,957,743	EPNG SoCal Ehrenberg	250	3,102,500
Calpine Energy Services, L.P.	988	9,113,794	PG&E Clygte Pool	736	6,579,128
AEP Energy Services, Inc.	880	8,398,119	PG&E Clygte Pool	291	2,489,500
Williams Energy Marketing & Trading Company	859	6,749,032	SoCal Topock EPNG	242	3,286,000
Enron Energy Services, Inc.	795	6,686,508	PG&E Clygte Pool	384	3,373,500

Note:
All transactions represent summaries of spot purchases, unless otherwise noted.
All volume traded includes weekends and holidays, unless otherwise noted.

Reliant was also highly active in western gas trading on EOL from a variety of perspectives:

- From November 1, 2000 through June 2001, Reliant had the 19 busiest days by trading volume (both buys and sells), and 30 of the 40 busiest days. On each of its busiest 3 days, it traded contracts for more than 1,800,000 MMBtu in volume, more than twice the busiest day of any other party. (See Appendix II-A, Table II-A1.)
- Reliant also had the 8 largest net purchase days in EOL spot trading for western gas from November 1, 2000 through June 2001, 9 of the 10 busiest days, and 32 of the 40 busiest days. (See Appendix II-A, Table II-A2.)
- Unlike Reliant's dominance on the purchasing side, several firms appear on the list of sellers with the largest net sales days (by net sales volume) in trading of western spot gas on the EOL system from November 1, 2000 through June 2001. (See Appendix II-A, Tables II-A3 and II-A4.) Five firms—SoCalGas (Sempra), El Paso, Dynegy, Duke, and Aquila—appear among the 10 biggest sellers. SoCalGas sold 600,000 MMBtu on November 22, 2000, the biggest single day of net sales. Note that this was the day

before Thanksgiving, so spot contracts sold on this day were for 5 days; SoCalGas's sales of 600,000 MMBtu represent 120,000 MMBtu/d.

- Reliant purchased more than 6,000,000 MMBtu each month on the spot market from December 2000 through February 2001. These monthly volumes were more than twice the size of the next largest monthly purchases by any other firm. Reliant was the top buyer for 4 of the 5 busiest months for net purchases. (See Appendix II-A, Table II-A5.)
- From November 1, 2000 through June 2001, Reliant had all of the 30 busiest trading days, defined by number of EOL trades executed for spot gas at Topock or Ehrenberg. The busiest day for a non-Reliant counterparty was March 23, 2001, when El Paso Merchant had 34 trades, the 40th busiest day. (See Appendix II-A, Table II-A6.)

Reliant's Purchases at Topock

From November 1, 2000 through June 2001, both Enron and Reliant frequently made net purchases using spot contracts on EOL that were large relative to the SoCalGas takeaway capacity (540,000 MMBtu/d) at that point. Contrary to statements sometimes made about Enron in general and Enron's EOL trading platform in particular, Enron did not simply act as a middleman matching buyers and sellers on EOL. Quite often, Enron would end a trading day with a substantial net physical purchase and, on some other days, a net sale.

On 39 different occasions, Enron or Reliant purchased more than 270,000 MMBtu/d at Topock (see Table II-2), representing more than half of the pipeline's takeaway capacity at that point. Enron purchased more than 270,000 MMBtu/d on 10 days and Reliant did so on 30 days. On December 12, 2000, both firms purchased more than 270,000 MMBtu/d. The combined purchases of Enron and Reliant exceeded 270,000 MMBtu/d on 29 days. These purchases are listed (in bold) among the 39 shown in Table II-2 below.

Regarding what constitutes a large physical purchase in the spot market, Reliant's head of gas trading stated, "Buying 200,000 for next-day gas is also a big amount for next-day gas."[14] Essentially, on quite a number of days, Reliant (and Enron, to a lesser extent) swamped the market point.

On 2 days during the period, each firm purchased more than 540,000 MMBtu/d, the total SoCalGas takeaway capacity. On these days,

[14]Interview with FERC Staff, September 2002.

Reliant's net purchases alone ensured that there would be cuts. Moreover, on 10 days the combined purchases exceeded the total SoCalGas takeaway capacity. Although, along with other customers, Reliant faced cuts in its nominations at Topock, at the same time Reliant was a substantial contributor to the situation there.

Table II-2. EOL Trading Activity in Topock Spot Gas, Days on Which Enron or Reliant Purchased More Than 270,000 MMBtu/d, November 2000 – June 2001

Transaction Date	Net Enron Purchases (MMBtu/day)	Net Reliant Purchases (MMBtu/day)	Combined Purchases (MMBtu/day)
	(1)	(2)	(3) = (1) + (2)
11/2/00	**290,000**	-45,000	245,000
11/3/00	**345,000**	-45,000	**300,000**
11/14/00	**340,000**	-45,000	**295,000**
11/27/00	195,000	**470,000**	**665,000**
11/28/00	**630,000**	-45,000	**585,000**
11/29/00	**555,000**	130,000	**685,000**
12/5/00	185,000	**289,000**	**474,000**
12/6/00	**345,000**	177,000	**522,000**
12/12/00	**282,000**	**410,000**	**692,000**
12/13/00	170,000	**557,000**	**727,000**
12/14/00	230,454	**322,000**	**552,454**
12/15/00	225,000	**452,000**	**677,000**
12/18/00	175,000	**460,000**	**635,000**
12/19/00	265,000	**270,000**	**535,000**
12/20/00	165,000	**380,000**	**545,000**
12/21/00	**348,000**	215,000	**563,000**
1/2/01	-80,050	**340,000**	259,950
1/3/01	-97,500	**570,000**	**472,500**
1/4/01	10,000	**310,000**	**320,000**
1/5/01	-40,000	**340,000**	**300,000**
1/10/01	-35,000	**270,000**	235,000
1/16/01	-40,000	**445,000**	**405,000**
1/17/01	45,000	**280,000**	**325,000**
1/22/01	-25,000	**380,000**	**355,000**
1/24/01	-15,000	**290,000**	**275,000**
1/29/01	**321,650**	-70,000	251,650
1/31/01	-40,000	**280,000**	240,000
2/1/01	-80,000	**370,000**	**290,000**
2/2/01	-66,000	**355,000**	**289,000**
2/7/01	25,000	**280,000**	**305,000**
2/12/01	-70,000	**410,000**	**340,000**
2/13/01	-97,500	**370,000**	**272,500**
2/14/01	-150,000	**410,000**	260,000
2/15/01	-157,500	**330,000**	172,500
2/16/01	-100,000	**345,000**	245,000
2/20/01	-90,000	**325,000**	235,000
2/21/01	-75,000	**305,000**	230,000
2/22/01	67,500	**390,000**	**322,500**
4/26/01	**384,512**	-10,000	**354,512**

Note: Daily totals shown in bold indicate net purchases of more than 270,000 MMBtu/d, representing more than half of the pipeline's capacity. Daily totals shown in bold and boxed indicate net purchases of more than 540,000 MMBtu/d, representing more than the pipeline's total capacity.

Reliant-Enron Churn Trades Sometimes Dominated a Day's Trading

On particularly active days of Reliant SoCal trading, trades between Reliant and Enron sometimes comprised the majority of the day's SoCal trading on EOL. Our subsequent analysis has determined that from November 1, 2000 through June 2001, there were 24 days on which Reliant both bought 100,000 MMBtu/d and sold 100,000 MMBtu/d (referred to as a "churn" day in this chapter) for next-day gas at the California-Arizona border. On the days when this took place, Reliant tended to buy and sell gas in rapid-fire succession. In many cases, this behavior had pronounced effects on prices. This churning by Reliant is something we did not observe for other firms.[15] In Figures II-4 to II-6, we provide representative examples of 3 days of Reliant churning in 2001: January 31, February 2, and June 11.

Figure II-4 depicts trading on Wednesday, January 31, 2001[16] for gas flow at Topock on February 1, 2001. On this day, 227 trades took place (2,240,000 MMBtu); more than 75 percent were transactions between Reliant and Enron. Each of the 101 blue squares in the figure is a purchase from Enron made by Reliant on EOL. Each of the 73 red crosses is a Reliant sale to Enron. The other 53 trades are between Enron and other counterparties (black crosses are Enron purchases from parties other than Reliant and purple squares are Enron sales to parties other than Reliant). The first transaction, at 8:00 a.m., is an Enron purchase of 10,000 MMBtu at $11.30/MMBtu (from El Paso). The last transaction, at 9:30 a.m., is a sale of 10,000 MMBtu from Reliant to Enron for $15/MMBtu. The grey horizontal line is Enron's average purchase price for the day, and the green line beneath it is Enron's average sale price. Enron loses money for the day trading Topock spot gas. The dotted red line is Reliant's average sale price to Enron, and the dotted blue line beneath it is Reliant's average buy price from Enron. For the first hour of trading, prices rise slightly, from $11.30 to $12. Once Reliant begins actively churning, the price rises quickly and steadily, peaking at $15.30 (Duke buying from Enron) and closing $3.70 higher than the price at which it opened.

[15]We define churning as days on which Reliant both purchased and sold at least 100,000 MMBtu. It was often the case that Reliant both bought and sold far more than 100,000 MMBtu.

[16]Most of the date references are to transaction dates, which typically take place 1 day before gas flow. For weekends and holidays, a transaction date may involve trading of a multiday packet of gas. For example, on Friday, December 8, 2000, a purchase of 10,000 MMBtu of gas on EOL was for flow on each day of December 9 to 11.

In total, Reliant bought 1,010,000 MMBtu of gas and sold 730,000 MMBtu, for a net purchase of 280,000 MMBtu. To achieve this, the Reliant trader entered into transactions at the rate of one every 10 seconds over the course of 30 minutes, producing sharp price movements on EOL that all traders would see without knowing the cause. We did not observe any other firm trading in this manner—either in terms of churning buys and sells or rapidly executing a large number of trades.

Figure II-4
Day-Ahead Trades at SoCal
January 31, 2001 for February 1, 2001 Gas

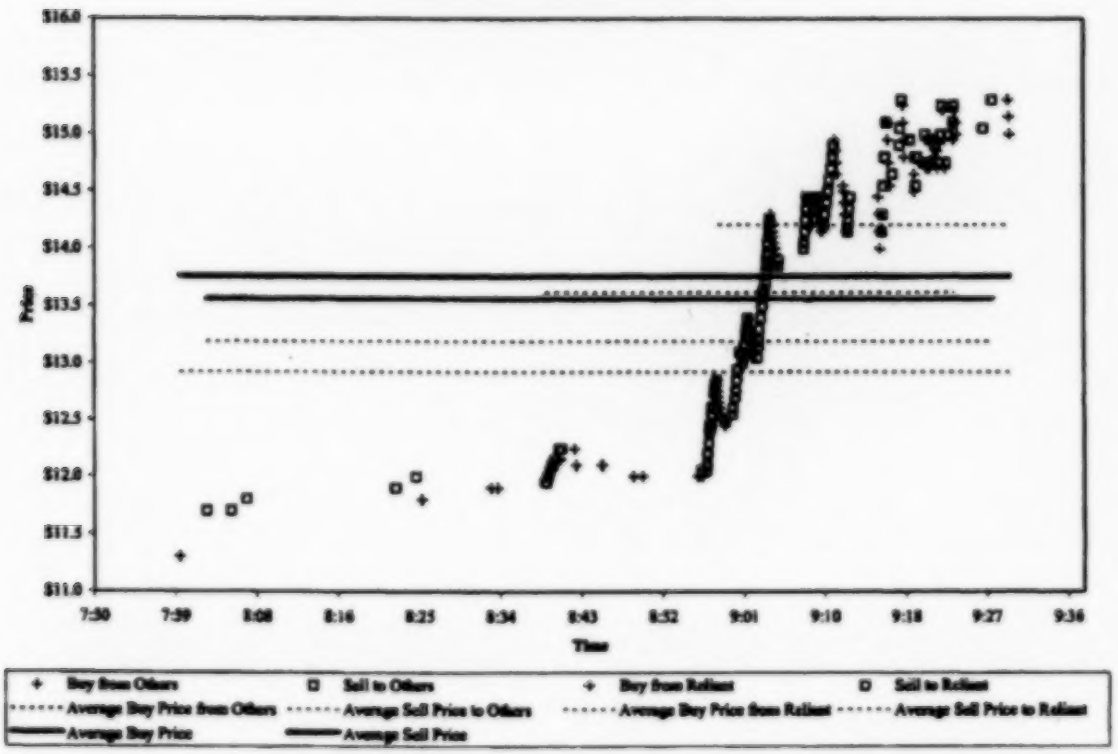
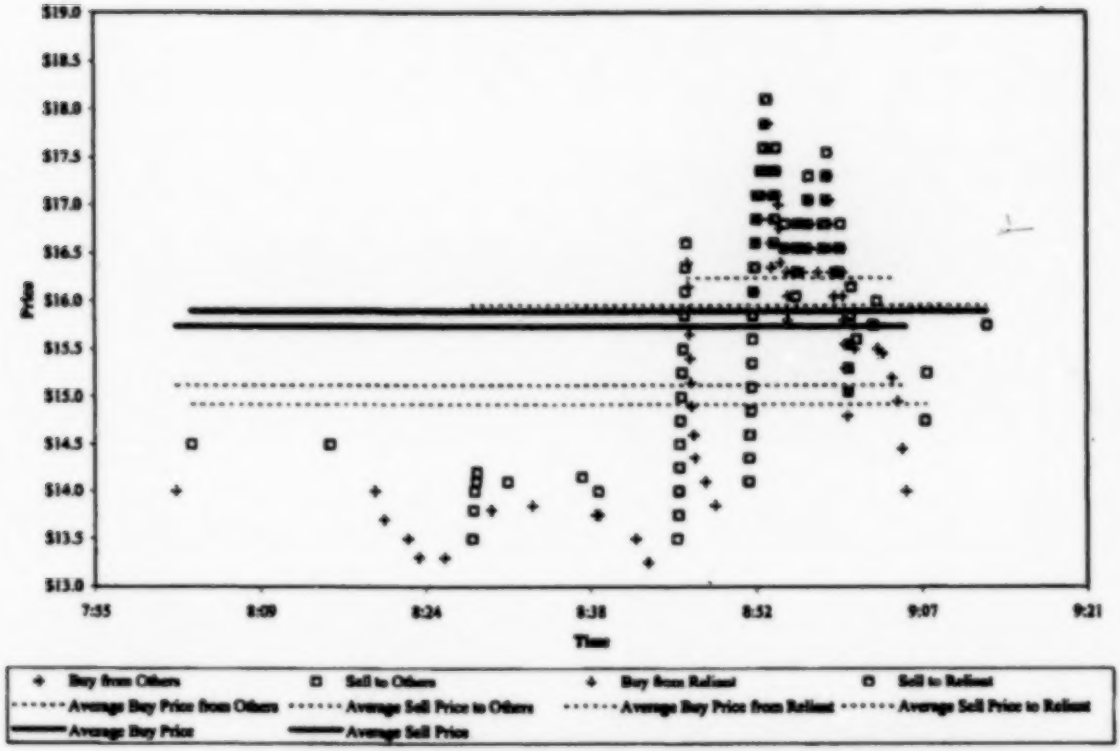


Figure II-5 depicts another Reliant churn day, February 2 for flow on February 3, 4, and 5. Again, we observe a pattern of Reliant buying and selling in extended bursts. In total, Reliant transacted 1,235,000 MMBtu of gas, for a net purchase of 355,000 MMBtu. Prices on this day began at $14/MMBtu (Mirant selling to Enron) and reached a peak of $18.10/MMBtu (Reliant buying from Enron) before closing at $15.75/MMBtu (Reliant buying from Enron). Trading lasted 70 minutes. The *Gas Daily* price for the day was $15.39/MMBtu. For the day, Enron's buy price was below its sell price, so in that sense Enron

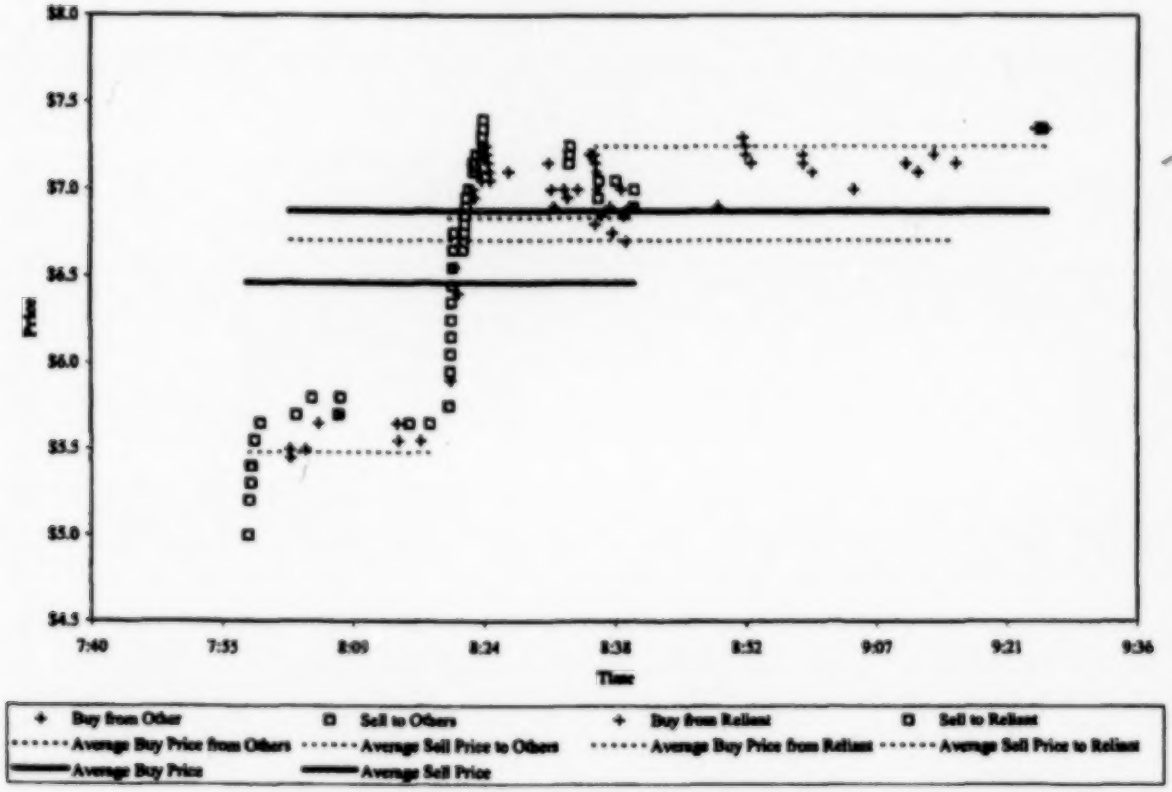
came out slightly ahead. Once again, Reliant's average sell price to Enron was above its buy price.

Figure II-5
Day-Ahead Trades at SoCal
February 2, 2001 for February 5, 2001 Gas



In Figure II-6, we see a somewhat different trading pattern. Here, Reliant does the bulk of its purchasing—400,000 MMBtu in 10,000-MMBtu increments—in a 5-minute time span and then sells off 224,000 MMBtu over the remainder of the trading interval, much of that in the last minute of trading. On this day, Enron's buy price is above its sell price. Reliant sells at a higher average price than it pays.

Figure II-6
Day-Ahead Trades at SoCal
June 11, 2001 for June 12, 2001 Gas



Reliant Trading and Market Volatility

Although Reliant was often a major factor in the SoCal points traded on EOL, there were days when Reliant's activity was fairly minimal. On those days, there were typically less pronounced price movements. Figures II-7 to II-9 depict three examples of days on which SoCal spot trading on EOL was fairly active but Reliant's churning did not play a part—November 28, 2000, January 29, 2001, and June 7, 2001.

What is most notable about these days is what is *not* observed—we do not see the rapid price swings up and down that are observed when Reliant churns. There are no bursts of trades at all, and prices remain flat for much of the day.

Figure II-7
Day-Ahead Trades at SoCal
November 28, 2000 for November 29, 2000 Gas

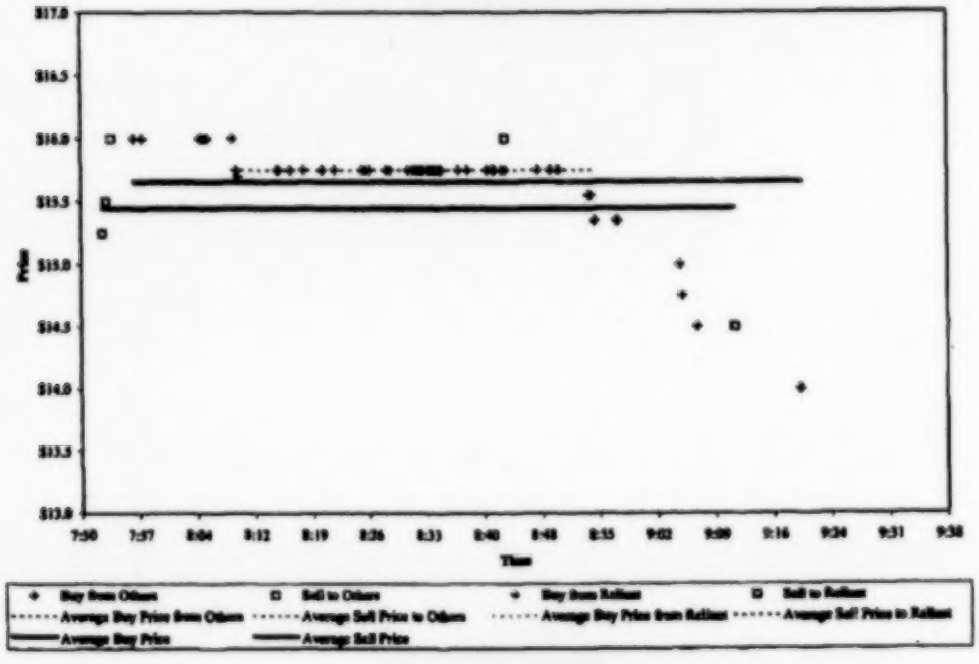


Figure II-8
Day-Ahead Trades at SoCal
January 29, 2001 for January 30, 2001 Gas

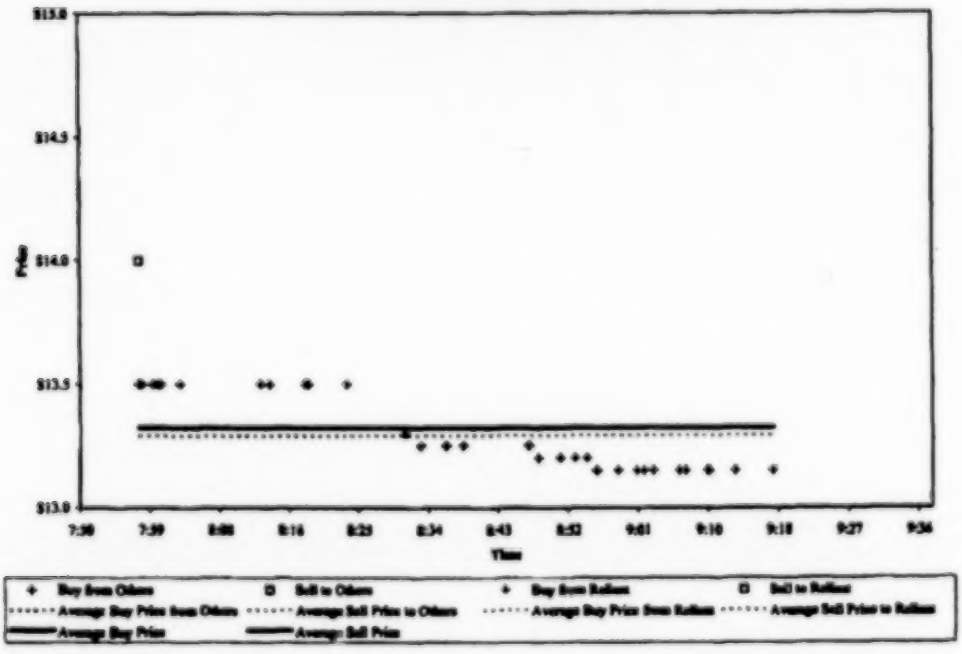
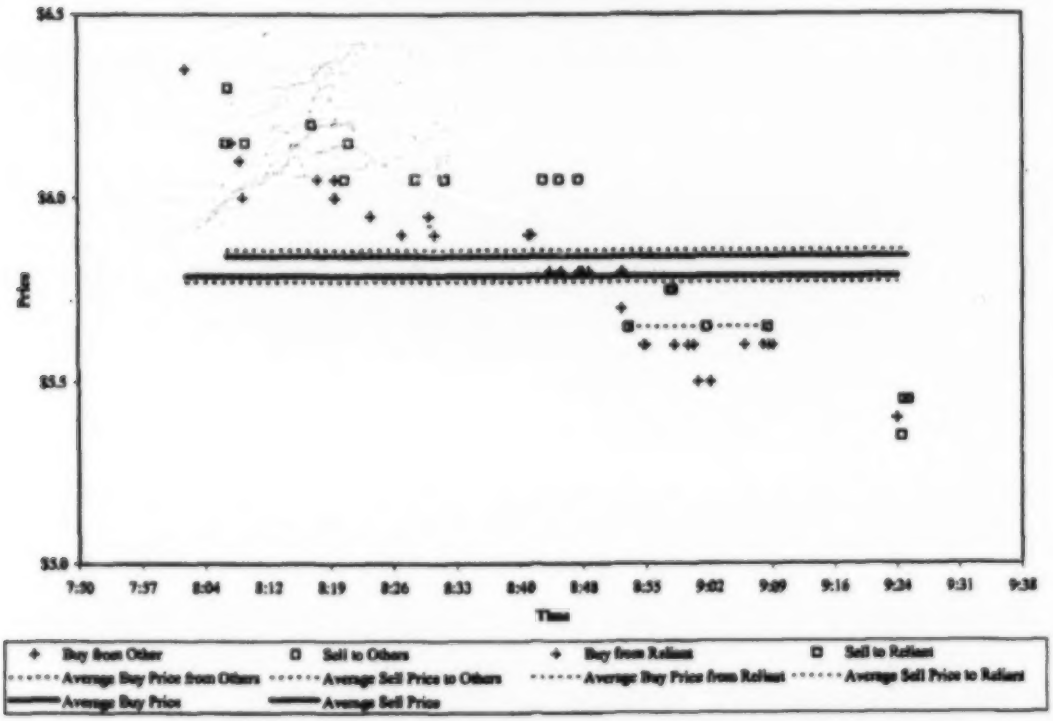


Figure II-9
Day-Ahead Trades at SoCal
June 7, 2001 for June 8, 2001 Gas



Figures II-7 to II-9 chart 3 relatively busy days at Topock on which Reliant was not a major force. The trading patterns observed on these days are visually quite different from those days on which Reliant was a major presence. No counterparty is seen to make bursts of purchases (or sales) in the way Reliant did. Trading activity is less frequent and price movements are less pronounced. Even when a number of trades in the same direction take place, such as on January 29, when counterparties sell to Enron repeatedly without an intervening purchase, we do not observe price movements of the sort that take place when Reliant rapidly enters into numerous transactions.

As a market point, the Topock point looks markedly different on the days of low Reliant activity. We also note that, rather than observing a balanced mix of both buyers and sellers transacting with Enron, what we see is tilted strongly toward counterparties selling gas to Enron. Enron was frequently a net buyer of spot gas at Topock.

Reliant Did Most of the Churning

After observing Reliant's churn trading, we performed an additional analysis to determine whether churn trading was found among counterparties other than Reliant or at other locations. As noted above, we defined churning as when a firm both bought and sold at least 100,000 MMBtu/d of spot gas on the same day for delivery at the same location. For the period from February 2000 through June 2001, we found 26 such instances. It was primarily Reliant that did this type of trading for all locations and counterparties; Reliant has 24 of the 26 churns (all at SoCal). (See Appendix II-A, Table II-A7.) While Reliant did not churn every day, it churned over the entire 8-month period and did so profitably, earning approximately $9 million from this trading strategy (see Table II-7 below).

Reliant's Churning

In this section we focus on Reliant's churn trading. We examine the days on which churning took place and the *Gas Daily* index and EOL prices on those days. We look at when churning was most prevalent, who within Reliant carried out the trades, and what this trading behavior may have looked like to the rest of the market at the time.

Reliant's Churn Days

Although our data sample begins in February 2000, Reliant's churning takes place from November 1, 2000 through June 2001. In Table II-3 below, we list each of the 24 days of Reliant's churning on EOL. On many days, Reliant's trading volumes were much higher than our definition of at least 100,000 MMBtu/d bought and sold. For example, on December 5, 2000, Enron's total trading volume for Topock was 1,465,000 MMBtu. Of this, 62 percent (911,000 MMBtu) was transacted with Reliant and 554,000 MMBtu was transacted with all other counterparties combined. Reliant's net purchase from Enron for the day was 289,000 MMBtu. Other counterparties sold 474,000 MMBtu (net) to Enron. So for the day, Reliant traded 622,000 more MMBtu gross (311,000 MMBtu bought and 311,000 MMBtu sold) than it bought net. On the following day, Reliant's trading comprised 60 percent of the day's trading volume.

Table II-3. Reliant Churn Days at SoCal (Topock and Ehrenberg), Summary of Physical Daily Trades of Reliant and All Other Counterparties

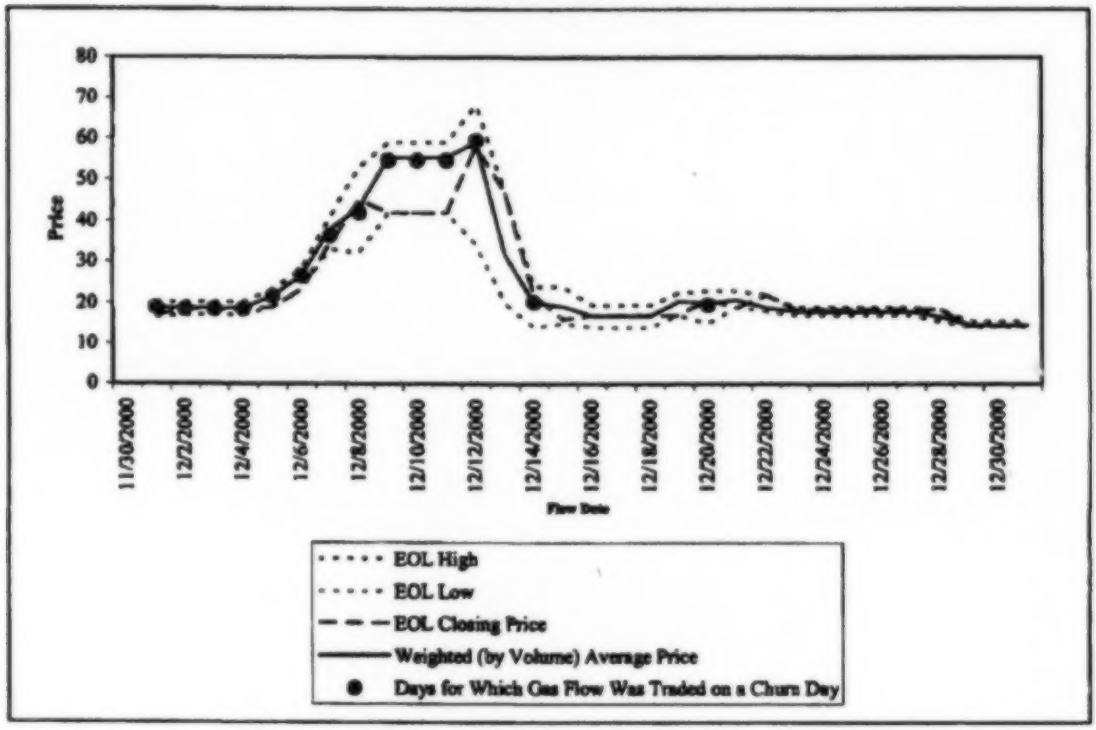
Transaction Date	Contracted Flow Date or Flow Period	EOL Gross Volume (MMBtu/d)	Reliant Gross Volume (MMBtu/d)	Reliant Net Volume (MMBtu/d)	Reliant Share of EOL Trading Volume	Reliant Churn Volume	Reliant Churn Volume Share of Trading
11/1/00	11/2/00	820,000	200,000	0	24.4%	200,000	100.0%
11/13/00	11/14/00	1,095,000	390,000	10,000	35.6%	380,000	97.4%
11/30/00	12/1/00	924,000	502,000	138,000	54.3%	364,000	72.5%
12/1/00	12/2 – 12/4/00	1,212,000	760,000	260,000	62.7%	500,000	65.8%
12/4/00	12/5/00	985,000	513,000	107,000	52.1%	406,000	79.1%
12/5/00	12/6/00	1,465,000	911,000	289,000	62.2%	622,000	68.3%
12/6/00	12/7/00	1,345,000	803,000	177,000	59.7%	626,000	78.0%
12/7/00	12/8/00	1,201,000	700,000	260,000	58.3%	440,000	62.9%
12/8/00	12/9 – 12/11/00	975,500	480,000	180,000	49.2%	300,000	62.5%
12/11/00	12/12/00	1,892,000	1,354,000	246,000	71.6%	1,108,000	81.8%
12/13/00	12/14/00	1,510,000	773,000	557,000	51.2%	216,000	27.9%
12/19/00	12/20/00	1,235,000	670,000	270,000	54.3%	400,000	59.7%
1/31/01	2/1/01	2,240,000	1,740,000	280,000	77.7%	1,460,000	83.9%
2/2/01	2/3 – 2/5/01	1,804,000	1,235,000	355,000	77.0%	880,000	71.3%
2/13/01	2/14/01	1,042,500	710,000	370,000	68.1%	340,000	47.9%
2/28/01	3/1/01	812,000	330,000	90,000	40.6%	240,000	72.7%
3/1/01	3/2/01	570,000	315,000	5,000	55.3%	310,000	98.4%
3/2/01	3/3 – 3/5/01	790,000	405,000	165,000	51.3%	240,000	59.3%
3/20/01	3/21/01	610,000	270,000	50,000	44.3%	220,000	81.5%
3/22/01	3/22/01	570,000	230,000	-30,000	40.4%	200,000	87.0%
3/23/01	3/24 – 3/26/01	1,105,000	670,000	30,000	60.6%	640,000	95.5%
4/3/01	4/4/01	538,012	220,000	-20,000	40.9%	200,000	90.9%
6/11/01	6/12/01	1,179,000	624,000	176,000	52.9%	448,000	71.8%
6/13/01	6/14/01	1,023,000	489,479	269,479	47.8%	220,000	44.9%

Reliant's Churning Peaked in December 2000

Of the 24 churn days shown in Table II-3, 8 are on consecutive trading days for delivery in December 2000. These particular days encompass the highest ever gas prices in California, reaching their peak on the eighth consecutive day of churning. The table shows that Reliant churning comprises more than 70 percent of its gross trading volume.

Figure II-10 charts price activity during December 2000, noting which days were churn days. The figure demonstrates that prices rose on most churn days. On the day after this string of churning ends, prices fall by more than $25/MMBtu. The price data are provided in Appendix II-A, Table II-A8.

Figure II-10
December Price Chart



Reliant Bought and Sold in Bursts

All transactions on EOL are initiated by the counterparty, not by Enron. Enron would constantly offer two prices—one at which it was willing to buy and a higher one at which it was willing to sell. It was up to counterparties, such as Reliant, to make the decision to transact. Enron could change its posted prices to encourage trading (e.g., by lowering the price at which it was offering to sell, a counterparty would be more likely to buy), but it could not initiate transactions.

Reliant initiated transactions with Enron in bursts unmatched by other counterparties:

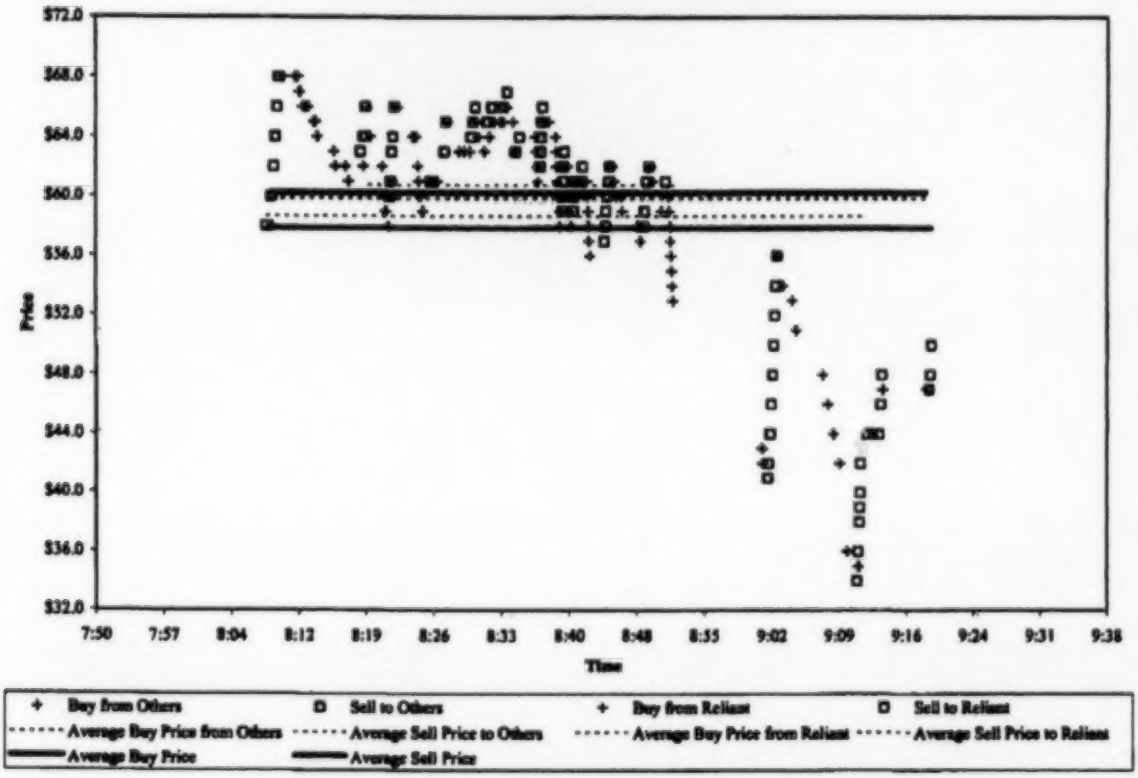
- From November 1, 2000 through June 2001, only once did another firm conduct as many as 10 trades at a single location within a clock minute (e.g., 8:51:00 a.m. to 8:51:59 a.m.); Reliant did this 14 times. Reliant was the trader for 38 of the 40 busiest minutes. (See Appendix II-A, Table II-A9.)
- When the time interval is increased from 1 clock minute to 5 clock minutes (e.g., 8:41:00 through 8:45:59), Reliant's trading pattern is even more unusual. No other firm ever made 15 or more trades in a single location within 5 minutes; Reliant did this 36 times. Reliant was the trading party for 39 of the 40 busiest 5-minute intervals. (See Appendix II-A, Table II-A10.)
- When observed somewhat differently, Reliant was by far the firm most likely to engage in consecutive trades for spot contracts on the EOL system. During one time span on January 31, 2001, Reliant made 43 consecutive trades before another firm conducted a trade. Reliant was the only firm to make more than 13 consecutive trades and was the counterparty for 34 of the 40 longest such streaks. (See Appendix II-A, Table II-A11.)
- In addition to being far more likely to engage in long stretches of consecutive trades, Reliant was also the most likely firm to transact a series of consecutive buys or sells without trading by any other firm. Reliant had the 4 longest streaks of consecutive purchases from Enron, as well as 8 of the 10 longest and 36 of the 40 longest streaks of consecutive purchases from Enron. (See Appendix II-A, Table II-A12.)

- In addition to long sequences of buy transactions and even though Reliant was usually a net buyer, Reliant also engaged in long sequences of sell transactions, although not generally as long as the buy sequences. Reliant transacted 6 of the 10 and 22 of the 40 longest streaks of consecutive sells to Enron (i.e., Enron buys). (See Appendix II-A, Table II-A13.)

Example of Effect of Burst Trading: December 11, 2000

Four of the forty longest uninterrupted sequences of trades (as shown in Appendix II-A, Tables II-A12 and II-A13), in which a single firm engages in consecutive trades, took place on December 11, 2000. On that day, Reliant bought contracts for 800,000 MMBtu and sold contracts for 554,000 MMBtu, resulting in a net purchase of 246,000 MMBtu for delivery the next day. (Figure II-11 shows the trading activity for this day, labeled in the same form as in Figures II-1 and II-4 to II-9.) This was a day on which the price varied particularly widely, ranging from $34 to $68; much of this variation took place during Reliant's stretches of consecutive transactions. Reliant opened its trading for the day at 8:09 a.m. with seven purchases (each for 10,000 MMBtu) within 45 seconds, during which the price rose from $60 to $68. At 8:51 a.m., Reliant sold eight contracts (each for 10,000 MMBtu) within 28 seconds, during which time the price dropped from $60 to $53; the next transaction took place at $43. At 9:02 a.m., Reliant bought 10 contracts (each for 10,000 MMBtu) within 62 seconds, during which time the price rose from $41 to $56. Reliant then stayed inactive until 9:11 a.m., when it made another series of 12 purchases (each for 10,000 MMBtu) in three groups, during which time the price rose from $34 to $50.

Figure II-11
Day-Ahead Trades at SoCal
December 11, 2000 for December 12, 2000 Gas



Reliant's final position for the day was a net purchase of 246,000 MMBtu at a total (net) cost of $12,606,000, for an effective net average price of $51.24/MMBtu.[17] This price is well below the price that the other two net purchasers paid on the same day, as well as below the day's weighted average price for sales to Enron, as shown in Table II-4. The *Gas Daily* index for the day reached its all-time high, $59.42, and Enron still paid $13 more than that—Enron paid, on average, $72.15 for its net purchases of 172,000 MMBtu.

[17]This calculation assumes no netting arrangement of the sort described elsewhere in this chapter.

Table II-4. EOL Trading in Topock Spot Gas, December 11, 2000

Firm	Total Purchases (MMBtu)	Total Sales (MMBtu)	Net Purchases (MMBtu)	Effective Net Average Price ($/MMBtu)
Net Purchasers				
Astra Power, LLC	10,000	0	10,000	64.00
Duke Energy Trading and Marketing, LLC	50,000	0	50,000	57.60
Reliant Energy Services, Inc.	**800,000**	**554,000**	**246,000**	**51.24**
Total	860,000	554,000	306,000	52.70[18]
Net Sellers				
AEP Energy Services, Inc.	0	5,000	-5,000	55.50
Aquila Dallas Marketing, LP	0	10,000	-10,000	60.50
Aquila Energy Marketing Corporation	0	90,000	-90,000	63.67
Coral Energy Resources, LP	0	25,000	-25,000	59.60
Dynegy Marketing and Trade	0	130,000	-130,000	57.46
Enserco Energy, Inc.	0	30,000	-30,000	62.13
Mirant Americas Energy Marketing, LP	0	48,000	-48,000	63.00
PG&E Energy Trading-Gas Corporation	0	10,000	-10,000	36.00
San Diego Gas & Electric Company	0	20,000	-20,000	43.00
Sempra Energy Trading Corp.	0	30,000	-30,000	62.33
Southern California Gas Company	0	60,000	-60,000	63.83
Texaco Natural Gas Inc.	0	15,000	-15,000	55.33
Tractebel Energy Marketing, Inc.	0	5,000	-5,000	65.00
Total	0	478,000	-478,000	59.70[19]
All External Firms (excluding Enron)	860,000	1,032,000	-172,000	
Enron	1,032,000	860,000	172,000	72.15[20]

[18]Weighted average of effective net average price for net purchasers, using the net purchases as the weight.
[19]Weighted average of effective net average price for net sellers, using the net purchases as the weight.
[20]Calculated as Enron's net payments of $12,409,500, divided by net purchases, 172,000 MMBtu.

Reliant's Trading Had the Effect of Maximal Market Impact

In Figures II-4 to II-6 above, one of the most visually striking elements is the nearly vertical line formed by the consecutive strings of Reliant's purchases and sales. When Reliant churned, it apparently made no effort to mask its activity. If anything, the opposite was the case.

Reliant's purchases typically took place in bursts, with successive purchases made at increasingly higher prices, seemingly running through the EOL "stack."[21] Given that there were sometimes more than a dozen purchases in a burst, it is quite possible that Reliant's bursts completely exhausted the stack. The same holds true for sales. Often when Reliant sold, it entered into several transactions in rapid succession, bringing prices down. In most cases, the net effect was an increase in prices (examined in more detail below).

Reliant's transaction pattern looks like the opposite of the usual expectation—buyers usually seek to minimize the extent to which they increase prices, and sellers usually seek to minimize the amount by which they bring prices down.

Reliant's Churning Raised the Index Prices

Because the published indexes report a midpoint (or an average) price for a day's trading, the churning activity inherently would bias the reported midpoint even if the churning had not affected closing prices.

When an index is based on an intraday average, the manner in which churning takes place is bound to affect the published index price. In the case at hand, churning raised prices, as Reliant typically began by buying and then later selling. In so doing, the initial buys raised prices. While the selling brought prices back down, the churning raised the day's median (and average) price.

For example, assume the day's prices open at $5/MMBtu and a company needs to purchase 50,000 MMBtu and uses one of two buying strategies. In the first strategy, it simply buys 10,000 MMBtu five times in a row and acquires the 50,000 at a median (and average) price of $5.20 (e.g., purchases of 10,000 MMBtu at prices of $5, $5.10, $5.20, $5.30, and $5.40, respectively).

[21] Essentially, the stack is a queue of bids and asks that the Enron trader would maintain in order to quickly replace a bid or offer when it was accepted by a counterparty, so that the product would remain available on counterparty traders' screens at all times.

In the second strategy, the company chooses to buy 30,000 MMBtu more (for a total of 80,000 in purchases) and then sell that 30,000, resulting in the same net purchase amount of 50,000. Using the same price pattern as above, purchases 6, 7, and 8 are made at prices of $5.50, $5.60, and $5.70, and the three sales are made at $5.70, $5.60, and $5.50. Although the net amount purchased equals 50,000 MMBtu, the median transaction price for these 11 transactions is $5.50, $0.30 higher than under the first strategy. The company's own average purchase price, however, remains the same, at $5.20.

Larger amounts of churning (where, as in Reliant's case, the sequence consisted of purchases followed by sales) would produce larger increases in the median and average prices.

Even if the day's closing prices for the two scenarios are the same, prices will have been higher throughout the trading day under the second strategy.[22]

Churning on EOL Showed Price Gyrations to the Whole Market

It is our understanding that virtually every gas trader had an EOL screen. EOL served as a common source for "price discovery"—traders looked to EOL for the current market price. One reason for this was that Enron always posted a "two-way"—a price at which it was willing to buy and a price at which it was willing to sell—and it is our understanding that Enron worked to keep its bid-ask spread as narrow as possible.

One implication of EOL's bid-ask prices, and changes in the bid-ask prices, being constantly observed by all gas traders is that as Reliant bought and sold in bursts, the whole market would see the resulting rapid, pronounced price movements. However, only Enron and Reliant would know *why* prices were moving when Reliant churned:

- Reliant always knew when its transactions were completed successfully, i.e., when its bids were accepted. So Reliant could see what happened to prices as it engaged in numerous successive transactions.
- Enron could see even more. Enron saw Reliant's activity along with every other trader's transactions and attempted transactions.

[22]However, forming index prices by using only transactions near the end of the trading day would risk manipulation of the shorter price-setting interval. The risk of manipulating closing prices might be larger than that of manipulating a day's worth of prices.

Other traders could see only that the prices on their EOL screens were seesawing up and down—in a manner not observed at other trading locations. With all that was going on in the western energy markets at this time, particularly in December 2000, it would be difficult to surmise what these traders were thinking. However, they could not know what only Enron and Reliant knew.

EOL was the most public place possible for Reliant's trading activities. In interviews (described further below), Reliant's SoCal spot traders indicate that they did not view their spot market purchasing patterns as unusually affecting the market. They stated that purchasing a relatively large quantity of gas might or might not affect prices, but that the way they went about buying and selling did not. On its face, this seems implausible. Reliant is the only firm that consistently "hit the button" rapidly and repeatedly, and Reliant did so only at the SoCal border. The graphs of entire days of trading are perhaps most telling in that they display both the rapidity with which Reliant was trading and the price movements that came with those bursts of trading. Figure II-5 shows that prices rose straight up when Reliant made its numerous bursts of purchases and prices dropped precipitously (although not as far) when Reliant sold in bursts. Reliant would have Staff believe that it bought large amounts in quick bursts, saw prices rise immediately, and tried to sell back on EOL at the highest of these prices, but had no idea that it was affecting market prices.

Reliant's Western Market Gas Trading Operations

In our review of trading records, it became clear that a single Reliant trader was responsible for all of Reliant's churning and almost all of its SoCal trading.

On Enron's side, two Enron traders shared responsibility for trading SoCal spot gas. On any day, one of these two traders would transact all of Enron's trades. Over time, each of these two traded Topock roughly equally. Both of these Enron traders were counterparties in the anomalous trading patterns, in approximately equal proportions. They traded Topock almost exclusively—when they were not trading spot gas at Topock, they were not trading much of anything else. Given that it is the counterparty that initiates all transactions, we decided to focus on Reliant's side of these transactions.[23]

[23]From Enron's perspective, the churning may not have been looked upon as problematic because Enron knew when it was taking place and who was doing it.

Given that the transaction patterns appeared to place no emphasis on minimizing the market impact of engaging in successive bursts of transactions, we considered a number of alternative hypotheses that might explain the observed trading patterns. Some of the possibilities are more benign than others. Possible alternatives included:

5. Reliant's SoCal trader was given a set of instructions—e.g., to transact primarily on EOL or to buy a specified quantity and/or to "balance" Reliant's needs—but was not responsible for the price paid (perhaps since it considered EOL liquid and robust).
6. The Reliant trader simply did not care about prices paid, and was unsupervised.
7. The trader's compensation structure gave an incentive to churn—e.g., the trader was allowed to buy and sell on account while filling Reliant's physical needs, and was somehow rewarded for churning.
8. Something more deliberate—e.g., a strategy of trading on EOL to drive up prices and benefit a financial position as well as potentially profit from the physical trades. A key question to address in this regard is whether higher index prices benefited Reliant's financial positions (discussed below).

Each of these possibilities has implications for the motivations and oversight of Reliant's management. Reliant may have been unaware that its SoCal spot trader was moving prices. Or, Reliant may have been unconcerned—or pleased—by such trading. In our examination of Reliant's behavior during this time period, among the steps we took were to examine Reliant's physical and financial trading records for southern California. This included:

- All Reliant physical trading on EOL, since this is where the index prices would be affected most directly.
- Reliant's SoCal trading in swaps, basis swaps, and balance-of-month swing swaps.
- All Reliant physical and financial trading with all counterparties, not just Enron on EOL.
- Examination for linkages between Reliant's financial trading activity and Reliant's anomalous EOL trading days.

After the Initial Report was published, Staff held interviews with Reliant traders and reviewed several key documents. In these interviews, Reliant reported that approximately 70 percent of its

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Additionally, it raised trading volumes and observed price movements, making the trading platform look both more vibrant and more liquid.

purchases in this time period were made on the spot market. In our discussions with Reliant traders and management, and from our review of Reliant's trading records, we gained an understanding of how Reliant carried out its trading activity, why this behavior took place at Reliant, and why Reliant stood out on EOL. A key factor in Reliant's gas operations was its contract with LADWP. During this time period, Reliant held a contract with LADWP to meet LADWP's gas needs for its power plants.

LADWP Contract

Reliant became LADWP's gas supplier in the summer of 1999, for a term of 1 year. This contract was renewed for an additional year; the second year includes the refund period.

Under the contract, LADWP was responsible for providing Reliant with estimates of its gas needs. LADWP was to make a monthly baseload nomination and subsequent daily swing nominations, and Reliant would then deliver gas to LADWP accordingly.

The pricing terms for this contract reflected the nominations arrangement. The price LADWP paid for its baseload nominations was based on the NGI monthly index. The price LADWP paid for its spot gas was based on the *Gas Daily* daily midpoint price. Three key implications of this contract structure are:

- Reliant would profit to the extent it could beat the published index prices.
- Reliant could minimize its price risk by matching its purchases for LADWP to LADWP's nominations, rather than (for example) holding a larger gas purchase portfolio and serving LADWP from it.
- LADWP did not benefit from Reliant's churning profits.

Southern California Gas Balancing Rules

Customers, such as Reliant, that used the SoCalGas intrastate system to serve customers had to contend with the SoCalGas balancing rules. In general, customers were expected to deliver gas in quantities that matched their usage. SoCalGas allowed its customers some tolerance from exactly matching nominations with usage. This tolerance was more stringent during the winter than the summer, and in the winter it was more stringent when physical system conditions—principally aggregate system storage levels—dictated it.

The SoCalGas balancing rules are regulated by the California Public Utilities Commission (CPUC). In all cases, balancing charges are invoked for a customer's failure to deliver sufficient quantities of gas. The level of the penalty is generally set at 150 percent of the highest reported spot price (over some relevant time period) multiplied by the amount the balance is below the tolerance. The balancing tolerance varies with SoCalGas's aggregate system storage balances.

Also, balancing rules are more stringent during the gas winter (November to March), including a set of triggers, based on the quantity of gas SoCalGas has in storage.[24] SoCalGas requires that customers deliver at least 50 percent of usage over a 5-day period from November through March. As SoCalGas's total (i.e., not customer-specific) storage inventory declines through the winter, the delivery requirement becomes daily and increases to 70 percent or 90 percent, depending on the level of inventory relative to peak-day minimums.[25]

Monthly Tolerance is 10 Percent

SoCalGas's monthly balancing charges apply to imbalances beyond 10 percent of the customer's usage for the billing period. Imbalance quantities beyond the 10 percent are subject to separate charges for underdeliveries and overdeliveries. Underdeliveries beyond the 10-percent tolerance band incur a charge calculated at 150 percent of the highest daily border price index at the Southern California Border for the month that the imbalance is created. The highest daily border price index is an average of the highest prices from NGI's "Daily Gas Price Index—Southern California Border Average" and the *Gas Daily* "Daily Price Survey— SoCal Large Packages Midpoint Price."

November 1 to March 31

From November 1 through March 31, SoCalGas transportation customers (such as Reliant) are required to deliver a minimum of 50 percent of usage over a 5-day period. In other words, for each 5-day period, if the total delivery is less than 50 percent of the total gas usage, a daily balancing charge is set at 150 percent of the highest Southern California Border price during that 5-day period (as published in NGI's Daily Gas Price Index).

Therefore, a single high-priced transaction, as reported by NGI, can raise imbalance penalty amounts considerably. This can have its own "death spiral" effect—any customer thinking it will face the 150-

[24]During the summer, SoCalGas applies a monthly charge only; the charge can be avoided by being no more than 10 percent out of balance for the month in total.
[25]Customers, such as Reliant, can hold storage capacity on SoCalGas's system. Reliant held no storage.

percent penalty charge will be willing to pay more than the current market price for gas to restore balance and avoid the charge. The result of this is that it raises the level of the 150-percent charge for everyone facing it.

The 70-Percent Rule

At the beginning of the winter, SoCalGas is required to have a certain amount of gas in storage. Additionally, there is a peak-day minimum requirement that there be sufficient gas in storage to provide deliverability for the core 1-in-35-year peak-day event, firm withdrawal commitments, and noncore balancing requirement. When total SoCalGas storage inventory declines to a predefined (and CPUC-regulated) "peak-day minimum + 20,000,000 MMBtu trigger," the minimum daily delivery requirement increases to 70 percent. Customers are then required to be balanced at a minimum of 70 percent of usage on a daily basis and the 5-day period no longer applies. The daily balancing standby rate is 150 percent of the highest Southern California Border price per NGI's Daily Gas Price Index for the day and is applied to each day's deliveries that are less than the 70-percent requirement.

For example, if on a given day when the 70-percent rule is in effect, total usage is 50,000 MMBtu and total deliveries are 30,000 MMBtu, then 5,000 MMBtu is subject to the daily balancing charge (70 percent times 50,000 minus 30,000 equals 5,000).

The 90-Percent Rule

When total SoCalGas storage inventories decline to the peak-day minimum + 5,000,000 MMBtu trigger, the minimum daily delivery requirement increases to 90 percent. Customers are required to be balanced at a minimum of 90 percent of usage on a daily basis. Similar to the 70-percent rule, the 5-day period no longer applies. The daily balancing charge is 150 percent of the highest Southern California Border price per NGI's Daily Gas Price Index for the day.

Storage Balances Are Published

Information regarding the established peak-day minimums, daily balancing trigger levels, and total storage inventory levels is made available on a daily basis on SoCalGas's Web site.

Having Gas in Storage Is Useful for Meeting the Balancing Requirements

There are a number of ways in which holding firm SoCalGas storage rights—and having gas in storage—can benefit a customer:

- Customers, such as Reliant, can nominate gas from storage to meet the 70-percent and 90-percent rules.
- At the customer's option, SoCalGas will use firm storage withdrawal volumes on behalf of the customer to match the customer's actual usage, as long as the customer has firm withdrawal rights and gas in storage.
- SoCalGas accepts intraday nominations to increase deliveries (including from storage).

What Happened in the winter of 2000–2001

During the winter of 2000–2001, SoCalGas gas storage balances dropped below the threshold level for switching from 5-day balancing to daily balancing on January 21, 2001, requiring customers to deliver 70 percent of their daily usage. As noted above, the penalty for being short was then set at 150 percent of the highest daily spot price.

The 70-percent requirement shifted to 90 percent on February 15, 2001 and lasted until March 17, 2001. During this period, each customer was required to deliver 90 percent of its daily usage or face the penalty set at 150 percent of the highest daily spot price.

From March 17, 2001 to March 31, 2001 (the end of the gas winter), SoCalGas operated on daily 70-percent balancing.

Because the imbalance penalties could be quite onerous, customers on SoCalGas's system needed to factor into their trading and nominating strategies the possibility of being assessed these penalties. To meet the balancing requirements, customers were willing to pay almost any price for gas because the alternative was to pay a penalty equal to 150 percent of the highest priced transaction reported by the index publishers. Reliant was one such customer.

Interview With Reliant's Southern California Spot Gas Traders

Staff interviewed Reliant's SoCal physical spot market traders[26] in September 2002. The intent of this interview was to learn more about how Reliant had carried out its trading operations during the time period of interest and about Reliant's primary SoCal physical spot market trader's role in particular.

From our review of Reliant's trading operations, we learned that these operations are divided between gas, power, and financial, and are split

[26]On any given day, one Reliant trader would perform this role. For virtually all of the time period of interest, one particular Reliant trader performed this function.

geographically within each of those areas. Reliant's SoCal physical spot market trader worked in the physical gas trading area of Reliant, focusing on southern California spot market gas.

Reliant's primary SoCal physical spot market trader's background includes both trading experience as well as employment in the research department at NYMEX. Essentially, this person came to Reliant with the plants that Reliant bought from Southern California Edison, where this person had been working as a gas buyer. As a new Reliant employee, this person continued in the role of gas buyer and took on the added responsibility of servicing LADWP's spot gas needs, which approximately doubled this trader's responsibilities.

Unlike the rest of Reliant's gas traders, Reliant's primary SoCal physical spot market trader worked from home in the Los Angeles area and had limited interactions with the rest of Reliant's traders. Reliant's primary SoCal physical spot market trader reports that the main contact person was Reliant's head of gas trading.

Reliant's SoCal physical spot market trader's primary responsibilities were to determine and meet the gas needs of Reliant's power plants and to meet its commitments to LADWP. The trader did this by communicating with personnel at the various plants and incorporating their estimates. Reliant would purchase all of the swing gas needed, which kept them quite busy during this period. A key responsibility was trying to avoid incurring the penalties from SoCalGas described above (and to which we return below).

Reliant's primary SoCal physical spot market trader states that trading typically lasted from 6:45 to 8 a.m. California time, a 75-minute interval. EOL trading records confirm that trading lasted about 75 (or as long as 90) minutes (although the exact time interval reported by Reliant's primary SoCal physical spot market trader varies from what we see on EOL). LADWP's nominations were due to Reliant at 7 a.m. California time. Trading on EOL for spot gas at the Arizona border typically stopped at about 7:30 a.m. California time (EOL used the Central time zone for time reporting purposes.)

It is clear that the time available was quite limited. On many days, as noted above, Reliant's primary SoCal physical spot market trader purchased (net) more than 300,000 MMBtu of gas from EOL alone (see Appendix II-A, Table II-A2).

Reliant's primary SoCal physical spot market trader's volume of gross transactions was often much larger, on one day reaching as high as 1,740,000 MMBtu, all of which was purchased in the typical EOL

maximum increment of 10,000 MMBtu. On that day, this trader's transactions were carried out in approximately 51 minutes, and 90 percent were carried out within a 30-minute interval, *an average of one trade every 10 seconds*.

Reliant's primary SoCal physical spot market trader offered several reasons for trading so extensively on EOL:

1. Availability/liquidity—Enron was always willing to transact, and the trader believed Enron's EOL prices were as good as any others and better than any other trading platform.
2. The view that one was not trading with Enron *per se*, but with a seller matched to one's purchases.
3. The netting arrangement this trader had with Enron (described below).
4. This trader's view that cuts at Topock were more predictable than those at Ehrenberg—that the benefit of any higher average flow at Ehrenberg would be more than offset by a perceived greater variance in cuts.

Netting Arrangements for El Paso Cuts

Reliant's netting arrangement with Enron had two important characteristics. The first was that purchases were treated at the average cost. A concern at this time for all buyers was the way in which a counterparty handled the cuts from El Paso. During this period, it was not unusual to expect a 40-percent cut in purchases at Topock. An entity selling gas might invoke price majeure—upon receiving its cuts from El Paso, the seller would then cut its counterparties in order of price. Accordingly, getting a lower price on a transaction might bring with it a lower probability of flow. This concern was especially important to Reliant, as it was such a large buyer in the spot market. The netting arrangement used average prices so that lower cost purchases could no longer be targeted for cuts. This gave Reliant an incentive to trade on EOL as a general matter.

The second important feature of the arrangement was that purchases were sheltered from cuts altogether up to the amount of sales made to Enron and any net profits from the sales were retained by Reliant. All of Reliant's purchases from Enron would be taken together to form a volume-weighted average price. All Reliant sales to Enron would be combined in the same way. When there are both sales and purchases, there are two separate calculations. The matching amounts (sales and purchases) would first be netted out against each other and the balance would then be settled at the respective average price. This is the

critical netting feature of the arrangement that gave Reliant an incentive to churn on EOL.

To see the effects of the netting feature, consider an example in which Reliant bought 200,000 MMBtu from Enron at an average price of $10 and sold 100,000 MMBtu at an average price of $15 on a particular day.

In one approach to handling this day's trades, shown in Table II-5, a 40-percent cut is applied to net purchases of 100,000 MMBtu and Reliant would purchase 60,000 MMBtu from Enron at an average price of $5/MMBtu, or $300,000.[27]

Table II-5. Netting Example—Settlement Without Netting

	Quantity Transacted (MMBtu)	Average Transaction Price ($/MMBtu)	Transaction Amount ($)
Total buys	200,000	$10.00	-2,000,000
Total sells	100,000	$15.00	1,500,000
Net purchase	100,000		-500,000
Average purchase price		$5.00	
Actual flow	60%		
Reliant's purchase price	60,000	$5.00	-$300,000

The actual netting agreement between Reliant and Enron worked as described in Table II-6. All of Reliant's purchases from Enron would be taken together to form a volume-weighted average price. All Reliant sales to Enron would be combined in the same way. When there are both sales and purchases, the matching amounts would first be netted out against each other and the balance would then be settled at the respective average prices.

[27]We use a 40-percent cut level as this is consistent with what has been represented to us by numerous sources as a typical cut level.

Table II-6. Netting Example—Settlement With Netting

	Quantity Transacted (MMBtu)	Average Transaction Price ($/MMBtu)	Transaction Amount ($)
Offsetting buys	100,000	$10.00	-1,000,000
Offsetting sells	100,000	$15.00	1,500,000
Netted amount	100,000	$5.00	$500,000
Additional purchase	100,000	$10.00	
Actual flow	60%		
Flowed quantity	60,000	$10.00	-$600,000
Reliant's purchase price	60,000	$1.67	-$100,000

If, on a given day, Reliant bought 200,000 MMBtu from Enron at an average price of $10 and sold back 100,000 MMBtu at an average price of $15, then 100,000 MMBtu would be netted out, with Reliant profiting $500,000 from the price spread. According to Reliant, this calculation is done first and, regardless of the cuts, the $500,000 profit to Reliant would not be affected. If the remaining amount purchased from Enron were cut by 40 percent, Reliant would be billed for 60,000 MMBtu at the average purchase price of $10, or $600,000. This would result in a net cost to Reliant of $100,000, with the full profit from its sales netted against its net purchase amount. This results in a purchase price for the 60,000 MMBtu of only $1.67/MMBtu. In fact, if the entire net purchase of 100,000 were cut, Reliant would still retain its $500,000 profit. Thus, purchases are sheltered from cuts up to the amount of sales and any net profit on the sales is retained.

Thus, there was a financial incentive to churn. Traders who think they can do better than average (presumably most traders) can lock in gains by churning, in a way that could not have been done without the netting arrangement (and that would have existed had there not been cuts on El Paso). Reliant's primary SoCal physical spot market trader reports that the netting arrangement was verbal, i.e., there was no paperwork.

It can be shown mathematically that whenever Reliant was a net buyer, there was a benefit to the netting arrangement that equaled the product of the price difference, the percentage cut (1 – the percentage delivered), and the quantity sold.[28]

[28]Assume that Reliant buys X (MMBtu) gas from EOL at price A ($/MMBtu), and sells Y (MMBtu) gas to EOL at price b ($/MMBtu). Suppose for this day's trades, the actual delivery rate is k percent. Without the netting agreement, Reliant pays aX dollars for the gas they bought and gets bY dollars for the gas they sold. In total,

Reliant's total profits from the netting agreement are shown in Table II-7. The table shows that profits from the netting arrangement were $8.9 million and that the majority of the profits came on days when Reliant churned.

Table II-7. Reliant's Profit From EOL-Reliant Netting Agreement, November 2000 – June 2001

	24 Churn Days	All Other Days	Total
Profit from the Netting Agreement	$7,267,962	$1,541,962	$8,809,924
Percentage	82.50%	17.50%	100%

Table II-8 shows the average purchase price that Reliant paid for gas under the netting agreement compared with what it would have paid if there were no netting agreement in place. It shows that the effective price differential (with and without the netting agreement) is substantial for churn days ($0.76/MMBtu) and negligible on other days ($0.03/MMBtu).

Reliant pays (aX - bY) dollars if all net purchases were delivered. When some gas gets cut, that is, when k percent is less than 100 percent, the total amount of money Reliant needs to pay to EOL is (aX - bY) * k. With the netting agreement, the churn portion of the buy and sell will cancel each other out first and a cash credit is given for every MMBtu if the sell price is higher than the buy price. The net purchase is then settled at the buy price. If Reliant acts as a net buyer (X > Y), the total amount of money it needs to pay to EOL is (X - Y) * a * k - (b - a) * Y. The possible advantage of the netting agreement to Reliant can be measured as:

$$
\begin{aligned}
&[(aX - bY) * k] - [(X - Y) * a * k - (b - a) * Y] \\
&= akX - bkY - [akX - akY - (b - a)Y] \\
&= akY - bkY + (b - a)Y \\
&= (b - a)Y - (b - a)kY \\
&= (b - a)(1 - k)Y
\end{aligned}
$$

That is, the advantage is the product of the price difference (sell-buy), the percentage cut, and the quantity sold. If Reliant acts as a net seller rather than a net buyer, the advantage of the netting agreement is the product of the price difference (sell-buy), the percentage cut, and the quantity bought. For a net buyer, the sell quantity Y is the churn quantity (the quantity that gets netted out). For a net seller, the buy quantity X is the churn quantity. Therefore, as buyer or as seller, Reliant's profit would increase proportionally to the churn quantity, independent of its actual net purchase or sales quantity.

Table II-8. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes, November 2000 – June 2001

		24 Churn Days	All Other Days	Total
Average Buy Price	Without the Netting Agreement	$24.36	$15.35	$17.08
	Applying Profit from the Netting Agreement, Assuming 60% Flow	$23.60	$15.32	$16.91
Note: Reliant was a net seller for three of the 24 Churn Days. The average buy price does not factor in those.				

Tables II-A14 and II-A15 in Appendix II-A provide details of the impact of the netting agreement (assuming 60 percent flow) on a daily basis for high-profit days (Reliant profit > $100,000). These tables show that the highest priced day in market history was also the day of the highest profits from netting—December 11. Tables II-A16 and II-A17 provide details of the impact of the netting agreement on a daily basis for all churn days. These tables show that Reliant lost money from netting on only 3 of 24 days, and that the total amount of losses was less than $30,000. In contrast, the netting arrangement resulted in a number of days of significant upside for Reliant. Tables II-A18 and II-A19 provide details of the impact of the netting agreement on a daily basis for all days in December 2000. These tables show that Reliant's profits from netting were approximately $5 million for December; virtually all of the profits occurred in the first 8 days of trading, when market prices rose to all-time highs.

Econometric Analysis of Reliant Trading Impact on Gas Prices

The previous sections of this chapter (along with Appendix II-A) document in detail that Reliant's SoCal trading on EOL stands out. No other firm traded in the manner in which Reliant traded, and Reliant's churn trading took place only during a highly unusual period for energy markets and only at one particular, key location—the California-Arizona border—where prices reached record highs.

However, this does not tell us whether or to what extent Reliant's trading impacted the market as a whole, which we discuss in this section. We performed the impact analysis in two steps:

1. We determined whether prices rose during the trading interval on the days Reliant churned.
2. We calculated the impact of churn on prices.

The first step in this impact analysis focused on the trading interval itself, as this is when Reliant could have affected the market most directly. During the November to June time period, prices generally rose sharply when Reliant made an uninterrupted series of purchases in a short amount of time. Similarly, we also observe that prices fell when Reliant made a burst of sales. The second step examines the effect of churn across days.

As the EOL prices rose and fell, they were seen by virtually all gas traders. In fact, as discussed in Chapter III, many traders used EOL as their main tool for price discovery and many reported the prices they saw on EOL to the Trade Press, who published the gas price indices.

Intraday EOL Price Analysis

This section examines whether SoCal prices rose during the 90-minute trading interval on the days Reliant churned. For purposes of this analysis, we define churn in two ways:

1. Days on which Reliant both bought and sold at least 100,000 MMBtu/d. Under this definition, Reliant either churned or it did not.[29]
2. The lesser of Reliant's daily total purchases and total sales. For example, if Reliant bought 50,000 MMBtu and sold 30,000 MMBtu (for a net purchase of 20,000 MMBtu), the churn variable takes on a value of 30,000 MMBtu.

The following descriptive statistics compare gas prices on churn vs. nonchurn days according to the first definition:

- The change in intraday price levels is significantly larger on churn days (+9 percent). The average intraday price change is 9 percent larger on churn days.
- The average price is more than $9/MMBtu higher on churn days ($22.02 on churn days vs. $12.79 on other days).
- The minimum price is $17.32 on churn days vs. $11.67 on other days.
- The maximum price is $24.56 on churn days vs. $13.85 on other days.

[29]We identified 24 such days for Reliant in the period, while there are only 2 churn days for all other counterparties combined across all EOL trading locations in the West.

- The spread between the maximum and minimum prices is greater on churn days, with a $7.24 spread on churn days and a $2.18 spread on nonchurn days.
- Measured from the start of trading to the close of trading, prices rose on average by $1.28/MMBtu on churn days and fell on average by $0.30/MMBtu on nonchurn days.

This suggests that the market behaved differently on churn days. Since Reliant churned on some days and not on others, we can examine the price impact with some relatively straightforward econometrics. In the econometric analysis, we include variables to control for other factors in order to determine, all else being equal, if prices rose more (or fell less) on days when Reliant churned. The econometric analysis uses EOL trading data for November 1, 2000 through June 2001, the period when the churning took place. Four variables are used to capture factors other than churning: one captures the effect of a transaction having taken place in December 2000, a second captures differences between Friday trading intervals for Saturday to Monday flow and other trading intervals for normal weekday flow, and the remaining two variables reflect basin price changes for western Canada (measured at Sumas, Washington) and San Juan.

For both regression specifications, churning is found to be positively correlated with intraday gas price changes and is statistically significant. Stated differently, when Reliant churned, prices rose on EOL and on the indices. The regression results are summarized in Appendix II-B.

We examined whether the results of our econometric analysis were robust. For example, changing the threshold for churn from 100,000 MMBtu/d to a different level (higher or lower) does not change results materially. Similarly, the results are also robust to changes in the time period considered (i.e., including earlier months along with November to June). Similarly, the results are unaffected by: (1) using other basin prices, (2) *not* controlling for the weekend effect or for the December effect, and (3) calculating the intraday price change using an average of the first few and last few sales rather than the first and last sales. With any of these changes to the model, the core result is unaffected—there is a statistically significant relationship between churning and increasing prices.

The clear statistically significant relationship between the churn variable and higher prices in the regression models suggests Reliant's churning artificially raised gas prices. In the next section, we estimate the net impact of churning on prices.

Interday EOL Price Analysis and Counterfactual Gas Prices

The second step in the impact analysis is to determine the extent to which the within-day price increase observed in the first step persists across days (i.e., whether the price increase caused by churning carried from one day to the next) and to estimate what the prices would have been in the absence of churning—i.e., to calculate counterfactual SoCal gas prices. By comparing the observed prices with the calculated counterfactual prices, we can determine the economic impact of churning.

The calculation of counterfactual gas prices is based on an econometric analysis similar to that described in the previous section, with some minor differences. First, the analysis examines interday rather than intraday price changes. Interday price changes reflect both intraday and overnight price changes. Second, the model captures the effect of churn on price changes on days after the day on which churn takes place, i.e., the model allows us to measure the persistence of the effect of churn. We model persistence by including lags of the churn variable.[30] Third, the model includes variables designed to capture the general tendency of prices to revert toward "equilibrium" values. We model mean-reversion—the general tendency of prices to revert toward "equilibrium" values—by including the lagged level of the EOL price and, in some specifications, additional variables.

Mean-reversion is an important component of energy price movements in both the long term and short term. In the long term, high prices induce further exploration and production, leading to increased supply. To the extent that demand is price sensitive, high prices may also reduce demand in both the long term and short term. By inducing additional supply and reducing demand, high current prices tend to lead to lower prices in the future. Conversely, low prices today tend to lead to higher prices in the future. The details of the model specifications and counterfactual calculations are provided in Appendix II-B.

We specify mean-reversion in two ways:

[30]We include three lags of churn in the model, i.e., we measure for churn's effect on price changes up to 3 days in the future. We have obtained qualitatively similar results by including different numbers of lags. We also include three lags of the relevant control variables.

1. *Equilibrium gas price varies as a function of the data.* We assume that levels of the control variables, such as basin gas prices, determine an equilibrium price. Price movements are a function of the difference between the lagged EOL Topock price and the equilibrium price. To the extent that the lagged price is above the equilibrium level, prices tend to fall (i.e., price changes are more negative). To the extent that the lagged price is below this equilibrium level, prices tend to rise (i.e., price changes are more positive).
2. *Equilibrium gas price is assumed to be constant.* This is a simplification of the first approach. Rather than modeling an equilibrium price that can change in response to changes in certain variables, we assume that the equilibrium price is fixed.

Which of these specifications is "better" is ultimately an empirical question.

Regression models are estimated over the entire period for which we have EOL data, i.e., February 7, 2000 to June 29, 2001. We focus on counterfactual prices from November 1, 2000 forward. This is also the period under consideration in the refund case and the period during which many long-term power contracts currently subject to litigation and renegotiation were signed.

The regression results are summarized in Appendix II-B. We report results for four different specifications based on two methods for measuring churn and two methods for modeling mean-reversion. The results of all specifications are similar and show that:

- Churn tends to elevate prices close to when it occurs, but the effect dissipates after several days.
- In every specification, when prices are high they tend to fall and when prices are low they tend to rise.
- Models in which the equilibrium price is allowed to vary fit the data better.

For a single instance of churning (where none takes place in the 3 trading days prior to or subsequent to the churn day), the counterfactual gas price calculation has several steps.[31] When churn days occur within 3 days of one another, the counterfactual gas price calculation is somewhat more complex. The following example assumes an isolated day of churn trading:

[31]The econometric specification uses logarithms. Accordingly, an additional step is exponentiation of the logarithmic results.

1. Using the EOL trading data, calculate the observed interday price change.
2. Using the results from the econometric analysis, determine the price increase from churn (the model specifies that the percentage increase is the same for every day on which churning takes place).
3. Subtract the churn-related price increase from the actual day-to-day price change.
4. Add the difference in step 3 to the previous day's closing price to form the counterfactual gas price.
5. The difference between the counterfactual gas price and the actual price is the amount attributable to churn.

Using the calculated counterfactual gas price, repeat this calculation iteratively for the next 3 trading days, after which we assume that actual and counterfactual prices are equal.

Rather than posit that there is one "true" econometric model that can produce counterfactual gas prices, we have performed the analysis in four ways that are largely similar to each other but differ in key ways. Using this approach, we observe that no matter the model specification, the results are essentially the same. Prices would have been lower in the absence of churning. The more churning that occurred, the higher the market prices.

One key difference between the models is that two specifications use the either-or specification of churn. Any day with more than 100,000 MMBtu/d of buys and 100,000 MMBtu/d of sells is a churn day. Any day with less buying or selling (such as a day with 300,000 MMBtu of buys and only 90,000 MMBtu of sells) is not a churn day. This specification of churn ignores what might be called "minor" churn days.

The other two specifications use a definition of churn that captures all days on which Reliant both buys and sells gas at SoCal on EOL. In so doing, these specifications give greater weight to the days with the most churning activity, unlike the either-or specifications, but also count the minor days of churning on which the behavior is far less pronounced. There are many instances of relatively small amounts of churning, especially in January, February, and April 2001.

The second difference between the model specifications is the treatment of mean-reversion. Two specifications assume a fixed

equilibrium price and two allow the equilibrium price to vary across time.

Table II-9 shows counterfactual prices computed from the four regressions presented in Appendix II-B. These are estimates of what spot prices for natural gas would have been at Topock if Reliant had not churned on EOL. We focus on December 2000, the period with the highest observed prices, a time span during the period under consideration in the refund hearings, and one of the months in which refunds potentially are largest.[32] The churn effect on gas prices is biggest in December because that is when the most churning takes place. For December 2000, a simple average of the four specifications' monthly average counterfactual gas prices is $8.54/MMBtu less than the average EOL prices. This is not to say that gas prices would have been precisely $8.54/MMBtu less in the absence of churning. It is simply the average from our four estimates.

Significant differences between actual and counterfactual gas prices also occur in February 2001 (when estimates vary from $1.30 less to $2.52 less per MMBtu) and March 2001 (when estimates vary from $1.94 less to $3.29 less per MMBtu).

For other months, the difference between the calculated counterfactual gas prices and the EOL and published index prices is lower. In May 2001, when there were no instances of buys and sells of at least 100,000 MMBtu/d, the counterfactual prices based on the either-or measure of churn are the same as the EOL prices, and the prices based on the alternative measure of churn are only 5 to 7 cents lower.

[32]Because FERC has limited refunds to "spot" transactions, potential refunds are larger for months during which significant volumes were transacted through the California Power Exchange (PX). The PX ceased trading in January 2001.

Table II-9. Counterfactual Price Summary

		Churn = Buys of at least 100,000 MMBtu/d and Sells of at least 100,000 MMBtu/d		Churn = Minimum of Buy Quantity and Sell Quantity		
Month	EOL Mean	Model 1	Model 2	Model 1	Model 2	EOL Mean – Average of All 4 Models
November	$9.66	$9.65	$9.64	$9.43	$9.26	$0.36
December	$25.26	$17.39	$16.69	$18.09	$14.70	$8.54
January	$12.82	$12.82	$12.82	$12.03	$11.09	$0.63
February	$18.57	$17.27	$17.19	$16.68	$16.05	$1.77
March	$14.76	$12.46	$12.34	$12.82	$11.47	$2.49
April	$13.72	$13.45	$13.44	$12.60	$11.09	$1.08
May	$11.77	$11.77	$11.77	$11.71	$11.68	$0.04
June	$6.06	$5.82	$5.80	$5.90	$5.84	$0.22
						Weighted Average: $1.91

Model 1 Time-varying equilibrium price assumed to be a function of independent variables.

Model 2 Constant equilibrium price is estimated.

Physical/Financial Linkages in Reliant's Trading

If the relationship that has been identified between interday and intraday price changes and Reliant's churning behavior is suggestive of Reliant's influence on spot prices on these days, a reasonable line of inquiry is whether Reliant's financial trading activity also benefited from its physical churn trading activity. The trades discussed in this section, like the physical trades already discussed, are bilateral in nature rather than exchange-traded or exchange-settled.

In this section, we present an analysis of Reliant's financial trading activity, focusing on how this activity aligns with physical trading activity and spot gas prices. We focus on Reliant's financial trading for trading activity just prior to periods of churning.[33]

[33] In the discussion below, we distinguish between the date that a trade is executed (i.e., the "transaction" date on which the trade occurs) and the date for which the trade applies (i.e., the "flow" date on which the trade is evaluated relative to a price index to ascertain the financial outcome).

How Gas Swaps Work

Reliant's financial trading consists primarily of various forms of financially settled swaps. In a swap, two counterparties execute a trade in which the buyer pays a fixed, known price for some notional quantity of gas and the seller pays a price that will vary with the market price (generally based on some agreed-upon price index), which will only be known later. Thus, the buyer in a swap transaction is going long—making a bet that the market price will rise—and the seller is betting that prices will fall. The two types of swaps that we examined are explained below:

- "Balance-of-month" (swing) swaps are intramonth swaps that applied for the remainder of the month, with settlement based on daily spot market prices throughout the duration of the contract. Similar to ordinary swaps, the buyer profits if gas prices rise.
- "Basis" swaps are trades in which the buyer pays, for some notional quantity of gas, a fixed, known price and receives the "to be determined" market price differential between two different locations—e.g., SoCal minus Henry Hub. Thus, the buyer in a swap transaction is betting that the price difference (the basis differential) between SoCal and Henry Hub will rise and the seller is betting that the basis differential will fall.

An example of how a trader can profit from a swing swap is provided in Tables II-10 and II-11. Table II-10 shows one of Reliant's swing swap transactions as an example. In the example, Reliant purchases a 10,000 MMBtu SoCal swap, which begins February 14, 2001 and lasts through February 28, 2001. If prices turn out to be higher than $17.50/MMBtu, Reliant profits.

Table II-10. A Swing Swap Trade With Reliant as Buyer

Buy/ Sell	Volume (MMBtu)	Price	Trade Date	Contract Begin Date	Contract End Date
Buy	10,000	$17.50	02/12/01	02/14/01	02/28/01

Table II-11 shows the outcome of the swap. On the first day of notional "flow," gas prices were $17.03 higher than the swap price, resulting in a $170,250 profit to Reliant. The next day, prices rose a little higher (to $19.29), resulting in additional profits of $192,900 to

Reliant. Over the next week or so, prices fell back to $17.50 and then lower. On February 28, prices were $5.05 below the $17.50 swap price, resulting in a loss to Reliant of $50,500 for the day. Cumulatively, the swap purchase resulted in a profit of $702,550 to Reliant.

Table II-11. Profitability of Swing Swap

Flow Date	SoCal Index Price ($/MMBtu)	Difference From $17.50 Swap Price ($/MMBtu)	Realized Profit for Day	Cumulative Profit From Trade
02/14/01	34.53	17.03	$170,250	$170,250
02/15/01	36.79	19.29	$192,900	$363,150
02/16/01	33.25	15.75	$157,500	$520,650
02/17/01	25.25	7.75	$77,450	$598,100
02/18/01	25.25	7.75	$77,450	$675,550
02/19/01	25.25	7.75	$77,450	$753,000
02/20/01	25.25	7.75	$77,450	$830,450
02/21/01	24.43	6.93	$69,300	$899,750
02/22/01	21.69	4.19	$41,900	$941,650
02/23/01	17.48	-0.02	-$200	$941,450
02/24/01	12.68	-4.82	-$48,200	$893,250
02/25/01	12.68	-4.82	-$48,200	$845,050
02/26/01	12.68	-4.82	-$48,200	$796,850
02/27/01	13.12	-4.38	-$43,800	$753,050
02/28/01	12.45	-5.05	-$50,500	$702,550

Reliant's Financial Trading Activity—Basis Trading and Swaps

Staff analyzed Reliant's financial gas trades, including basis trades and swaps having different effective start dates and durations, to establish Reliant's net financial position at each point in time (i.e., each day) over the period of interest. The net financial position takes into account any prior trade (possibly occurring as early as several months earlier or as late as the previous day) that affects the Reliant financial position at the start of the day. The trades that affect the net financial position on any day comprise both basis trades (generally monthly) and swaps (generally rest-of-month).

Reliant's Southern California Basis Trades

Our analysis of Reliant basis trades used the net financial position resulting from trading activity that occurred prior to the start of the month. We compiled, on a cumulative basis over time, the net financial position for basis trades that apply to a given month for November 2000, December 2000, January 2001, and February 2001. Our calculations do not appear to suggest any type of systematic positions or trading activity on the part of Reliant that would indicate it attempted to structure its financial basis trading behavior so as to benefit from its physical trading activities.

Reliant's Southern California Swaps

Figure II-12 shows the daily net financial position for Reliant for the period November 1, 2000 through February 2001 as a result of financial swaps. The figure shows that Reliant's daily net financial position ranged from a short position of 75,000 MMBtu/d on November 16, 2000 to a long position of 65,000 MMBtu/d between January 20, 2001 and January 31, 2001.[34] From November 2000 through February 2001, there are three subperiods during which Reliant changed its net financial swap position markedly from a short position to a long position, and maintained the long position for a number of days. These three subperiods began on or about December 1, 2000; January 18, 2001; and February 12, 2001.

In addition to Reliant's net financial position, Figure II-12 also shows the *Gas Daily* spot price for SoCal.[35] The *Gas Daily* SoCal spot price is relevant because it is the reference price for settlement of Reliant's swaps that apply to a particular day. To the extent that Reliant has a net long financial position on a given day, the difference between the *Gas Daily* spot price and Reliant's weighted average swap buy price (i.e., across all trades affecting the net position for the day) will determine the profit that Reliant will realize on its net financial position for the day.

[34]The daily swap net position is calculated using the trading records provided by Reliant.
[35]*Gas Daily* SoCal Large Packages Midpoint Price.

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Figure II-12
Reliant's Daily Swap Net Position and *Gas Daily* SoCal Large Packages Midpoint Price Index
November 2000 – February 2001

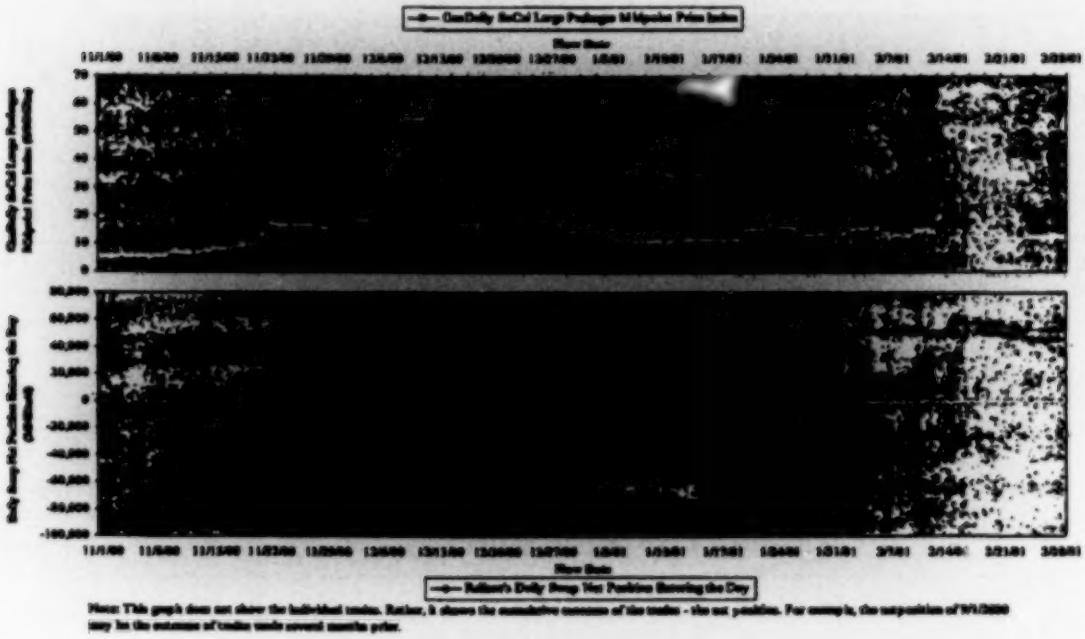


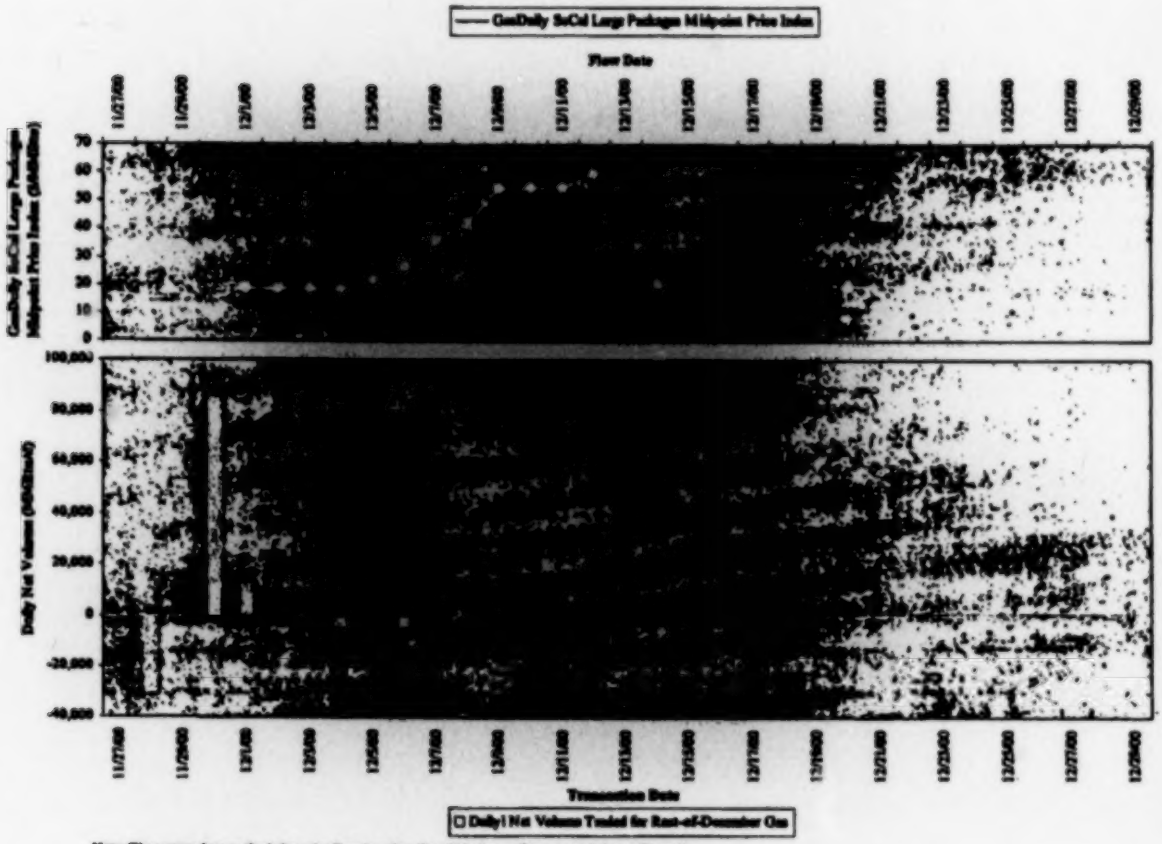
Figure II-12 shows that of the three times when Reliant shifted noticeably to a net long position (i.e., Reliant would benefit from price increases), for two of these periods it did so just prior to a sharp increase in the *Gas Daily* SoCal spot price. If this net financial position were taken in anticipation of the spot price increase, Reliant would benefit. One hypothesis suggested by the analysis of physical trading activity is that Reliant may have influenced prices on certain days; one motive would be to reap the benefits of its financial trading positions on those days. Collaboration between physical and financial trading could explain the timing of the price increase coinciding with moving to long net financial positions.

Subperiod 1: November 27 Through December 31, 2000

Figure II-13 provides a closer look at the trading activity of a particular Reliant trader, "financial trader A," for one period of interest, November 27, 2000 through December 31, 2000. It shows the average net position in swaps (for rest-of-December gas) and the SoCal spot price for each day. This trader purchased a large number of swaps on November 30, 2000.[36] As shown in Figure II-13, on November 30, 2000 financial trader A made trades that resulted in a long position of 85,000 MMBtu/d just prior to a series of 8 consecutive days of churn trading. The profits associated with financial trader A's financial trading for November 30 to December 1, 2000, just prior to this period of consecutive churn days, were more than $23.4 million (shown in more detail in Table II-A20 in Appendix II-A). Essentially, this $23.4 million profit results from the purchase of 85,000 MMBtu/d of SoCal swing swaps for December, just prior to an unprecedented increase in SoCal gas prices and at the beginning of 8 consecutive days of Reliant churn trading.

[36]Note that financial trader A accounted for 78 percent of the gross volume of Reliant financial swaps for this period.

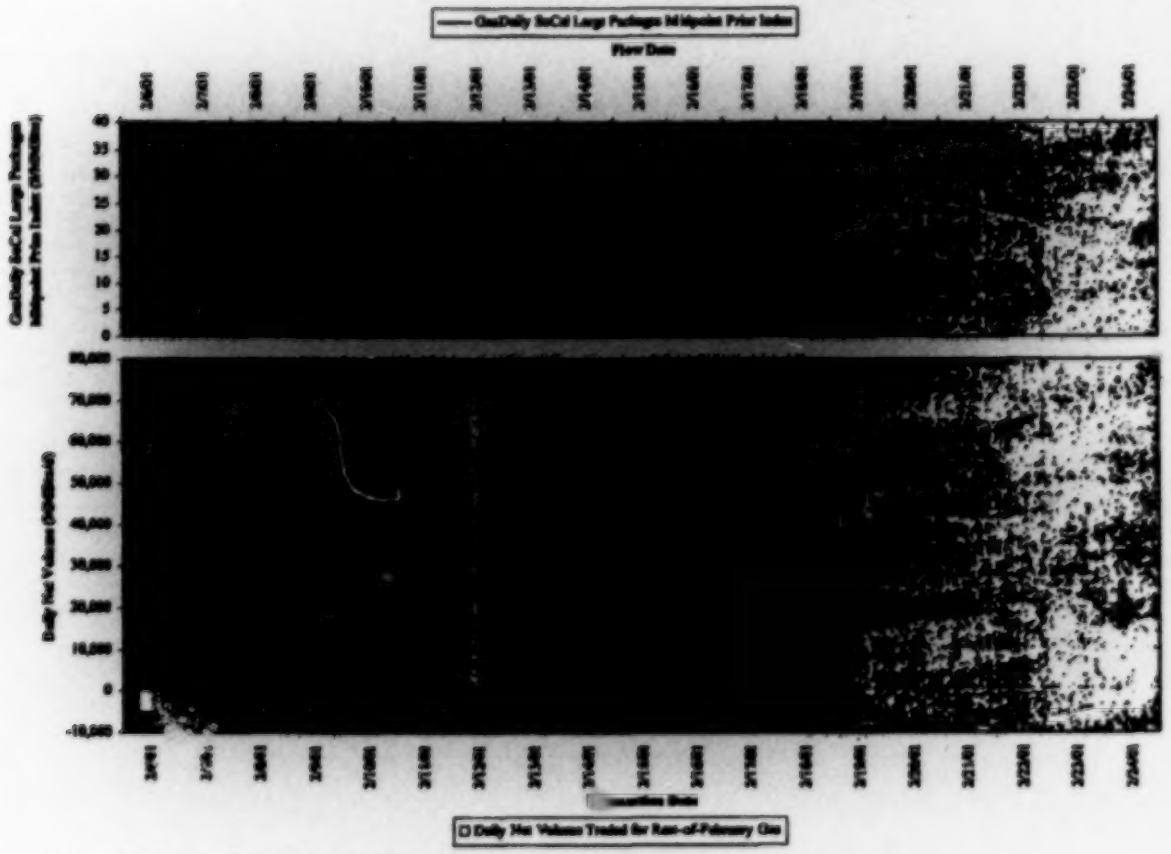
Figure II-13
Financial Trader A's Daily Net Volume Traded for Rest-of-December Gas, Compared With *Gas Daily* SoCal Large Packages Midpoint Price Index
November 27, 2000 – December 29, 2000



Subperiod 2: February 6 Through February 24, 2001

Figure II-14 provides a closer look at financial trader A's trading for the second subperiod of interest, February 6, 2001 through February 24, 2001. During this period, February 13 trading (for flow on February 14) was the only churn day. From February 14 through February 24, 2001, gas prices were substantially higher than they had been for the first part of February. On February 12, 2001, financial trader A bought 13 swaps that resulted in a long position of 70,000 MMBtu/d. February 12, 2001 was the day prior to the only churn trading day in the period, and the SoCal spot gas price of the gas flow traded on this day rose sharply to $34.53/MMBtu. The profits associated with financial trader A's financial trading for February 12, 2001, were $4.4 million. (See Appendix II-A, Table II-A21.)

Figure II-14
Financial Trader A's Daily Net Volume Traded for Rest-of-February Gas, Compared With *Gas Daily* SoCal Large Packages Midpoint Price Index
February 6, 2001 – February 24, 2001



Note: The orange dot on the index price line shows the day for which the gas flow was traded on a Cleave day.
The Daily Net Volume Traded accounts for contracts starting the next day or the day after and last through the end of the month.

Of the approximately $23 million that Reliant derived from financial transactions in December 2000 that were pegged to natural gas spot prices at the Southern California Border, approximately $17 million was attributable to the increase in physical gas prices caused by its churning. Of the approximately $3.8 million that Reliant derived from financial transactions in February 2001 that were pegged to natural gas spot prices at the Southern California Border, approximately $1 million was attributable to the increase in physical gas prices caused by its churning. In sum, Reliant derived profits from financial transactions of approximately $18 million due to churning during the relevant 8-month period.

Conclusion Concerning Reliant Trading

At certain times, Reliant employed a churning strategy for buying physical spot gas at Topock on EOL. Reliant needed this gas to generate and sell power into the spot market and to fulfill its contract for supplying gas to LADWP. Reliant's churning strategy involved the repeated buying and selling of substantial quantities of spot gas in a very short period of time in amounts far in excess of its actual needs. When churning, Reliant often traded in bursts unlike any other trader by executing a large number of purchases and sales in a short period of time—sometimes entering into transactions at the rate of one every 10 seconds. No other firm ever made 15 or more trades in a single location within 5 minutes; Reliant did this 36 times. Reliant dominated the churn trading, accounting for 24 of the 26 instances we found; this includes 8 consecutive trading days for December 2000, which encompass the highest-ever gas prices in California. Over this critical 8-day churn period, Reliant's churn volume comprised more than 70 percent of its gross trading volume. On the day after this string of churning ends, prices drop by more than $25/MMBtu.

For trading volume, Reliant had the 19 busiest and 24 of the 25 busiest trading days on EOL. At Topock and Ehrenberg in particular, Reliant had all 30 of the busiest trading days, measured by number of trades executed. As such, the assumption of liquidity at Topock was often invalid—on a number of days most of the EOL trades took place between Enron and Reliant, rather than there being a more diverse mix of active traders. For the 3-month period from December 2000 to February 2001, nearly 50 percent of the spot gas trades on EOL were with Reliant. For the other 5 months of the refund period, Reliant's share varied between 20 and 30 percent. On the day of the highest Topock prices (flow date of December 12), Reliant accounted for more than 70 percent of the trading volume.

In addition, Reliant often swamped the Topock delivery point with its net gas purchases. On 30 separate occasions, Reliant's net purchases of gas were in amounts greater than half of Topock's 540,000 MMBtu/d capacity. In fact, on two occasions, Reliant's net purchases exceeded the total capacity at Topock. On these days, Reliant's net purchases alone ensured that there would be cuts at Topock.

Reliant's rapid-fire sale and purchase of gas in amounts far in excess of its needs raised the price of gas on EOL significantly. On average, the price is $9/MMBtu higher on churn days than on other days.

Reliant's churning also resulted in significant price volatility. The within-day price spread is $5/MMBtu greater on churn days than on other days.

Reliant was able to benefit from churning even though this raised prices and Reliant was a net buyer of gas for its needs. This is because Reliant was often able to profit from the price run-up it caused by unloading its unneeded gas at the higher prices. In spot market trades, Reliant earned more than $8.8 million from its churning and had a netting arrangement with Enron that sheltered its sales from cuts on the El Paso pipeline. Trading under this arrangement allowed Reliant to reduce its average cost of purchasing gas by more than $0.75/MMBtu on churn days.[37]

Reliant deliberately bought and sold gas in a manner that had the effect of raising prices and used its netting agreement with Enron to capture the related profits. It used these profits to reduce the total cost it paid for the gas it needed. Reliant traded Topock gas almost exclusively on EOL, and virtually every trader had an EOL screen. As a result, the price gyrations caused by Reliant were seen by the whole market; however, only Reliant and Enron knew what was causing the price movements. Since EOL served as the primary source for price discovery, its prices virtually mirrored those of *Gas Daily*. Reliant's churning had the effect of moving the entire market price by an average of some $8.54/MMBtu for December 2000 and by an average of $1.91/MMBtu over the 8-month period that it churned. These figures represent the average of analyses we have performed in four different ways. All of the analyses are fundamentally alike, but deal in slightly different ways with certain input variables. Notably, the results of all four analyses are the same—Reliant's churning raised prices, and the more Reliant churned, the higher the prices rose.

Deliveries into SoCalGas at the California-Arizona border are considered as one pricing point in *Gas Daily*. If we assume that Reliant's trading affected the entire gas volume of 2,500,000 MMBtu/d delivered into SoCalGas at the California-Arizona border,[38] customers paid excessive gas costs in the neighborhood of $650 million for December 2000 and about $1.15 billion for the 8-month period.[39] More significantly, if we assume an average load in the

[37] Assuming 60 percent flow.

[38] El Paso into SoCalGas at Topock of 540,000 MMBtu/d and at Ehrenberg of 1,210,000 MMBtu/d, and Transwestern into SoCalGas at Needles of 750,000 MMBtu/d.

[39] Not all of the gas entering SoCalGas's system transacts, at least initially, at daily index prices. In particular, some gas flows under prices tied to a monthly index. However, monthly gas may be resold at index prices and intrastate California production may also transact at a price tied to a daily index.

California spot market of 20,000 MW for November through the end of the PX in January 2001 and 5,000 MW thereafter through June 2001, an excessive gas price of $8.54/MMBtu (about $85/MWh) would inflate electric clearing prices by some $1.2 billion for December 2000. Overall, an excessive gas price of $1.91/MMBtu[40] (about $19/MWh) would inflate electric clearing prices by about $1.6 billion.

Reliant priced all the spot gas it sold to LADWP at index prices. Reliant used the spot gas it purchased for itself to generate and sell power at spot market prices, which reflected the indices. Therefore, Reliant was largely insulated from the increase it caused in the market price of spot gas and effectively bought cheaper gas for itself at everyone else's expense.

We know Reliant had the ability to unilaterally move the market price through churning, and that it did so. Our econometric evidence is clear on this point. Second, we know that Reliant had a financial incentive to influence prices by churning, and that it profited by doing so. Our analysis of the netting arrangement makes this clear. Third, we know that churning pushed up the price paid by all participants whose costs were tied in one way or another to spot market index prices.

Recommendation: Remedial Action To Address Reliant's Churning

Reliant profited from churning in both the physical and financial markets. In so doing, Reliant adversely impacted prices to such a significant degree that remedial action is justified.

The Commission has authority to regulate commodity sales that do not constitute "first sales."[41] Sales that are not first sales are sales of gas by an interstate or intrastate pipeline, a local distribution company (LDC), or an affiliate thereof. During 2000 and 2001, Reliant was an affiliate of an interstate pipeline and thus its sales were not first sales, i.e., its sales were subject to Commission jurisdiction. In late 2002, Reliant was spun off and is no longer affiliated with a pipeline. Therefore, its sales are now first sales.

[40]To form an average for the 9-month refund period, we assume zero churning effect for October 2000, for an average price effect of $1.69/MMBtu.

[41]First sales are defined in Section 2(21) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. § 3301(21) (1994). The Commission does not have jurisdiction to regulate first sales pursuant to Section 601(a)(1)(C) of the NGPA, as amended by the Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60.

Section 284.402 of the Commission's regulations[42] authorizes any person who is not an interstate pipeline to sell gas for resale in interstate commerce at negotiated rates. The gas cannot involve first sales but must be within the Commission's jurisdiction.[43] Gas sold by Reliant is subject to the Commission's jurisdiction, i.e., it does not constitute a first sale because it was sold by an affiliate of an interstate pipeline. Reliant's churning did not violate Section 284.402 of the Commission's regulations because those regulations contain no explicit guidelines or prohibitions for trading gas.

Staff recommends that Sections 284.284 and 284.402 of the regulations be amended to provide explicit guidelines or prohibitions for trading natural gas under Commission blanket certificates. Staff also suggests a generic proceeding to develop appropriate reporting and monitoring requirements for sellers of gas under Commission certificates.

[42] 18 C.F.R. § 284.402 (2002).

[43] For example, Order No. 637-A, FERC Stats. & Regs, Regulations Preambles ¶ 31,099 at 31,603 (1999). ("To the extent that the gas sale is a first sale, it would not be jurisdictional, and for jurisdictional gas sales, the Commission has already granted a blanket certificate to make sales for resale at negotiated rates.")

III. Manipulations of Published Natural Gas Price Indices

On August 13, 2002, the Commission made publicly available Staff's Initial Report of its investigation in Docket No. PA02-2-000. Staff inquired into the characteristics of publicly reported price data, including natural gas spot prices at California delivery points that are used in the California refund proceeding. Staff found significant problems with published price indices and specific issues with respect to California delivery point spot prices, as described below:[1]

- The Commission cannot independently verify the published price data (primarily because the source of the publications' raw data has not been disclosed due to publishers' confidentiality concerns about revealing source data).
- Undetected errors may exist because trade publications reporting spot and forward prices do not employ statistically valid sampling procedures or a systematic, formal verification procedure.
- Market participants have significant incentives to manipulate spot market prices reported to the reporting firms because natural gas is the fuel input for the electricity generators that set the market price in California.
- Wash trades may have an adverse effect on reported price data.
- EnronOnline (EOL), Enron's former electronic trading platform, was a significant source of price discovery and formation and was potentially susceptible to manipulation by market participants, which could affect the published price indices.

Based on these findings, Staff concluded that published California delivery point natural gas spot prices are not sufficiently reliable to be used in the California refund proceeding for purposes of calculating the MMCP and resultant refunds. A detailed discussion of the alternative proposal is in Chapter IV.

[1]These findings are summarized in the Initial Report on pp. 3-5 and 34; a detailed discussion is provided on pp. 35-57.

Developments in the Investigation Since August 13, 2002

Since the Initial Report was issued, five companies (Dynegy, AEP, Williams, CMS, and El Paso) have admitted that their employees provided false data to the Trade Press.[2] On December 2, 2002, the Office of the United States Attorney in Houston indicted a former vice president of El Paso Energy on charges of false reporting and wire fraud in connection with his reporting of false trades to *Inside FERC* on November 30, 2001. These false trades were to be part of the calculation for the December 2001 monthly price index for the Sumas trading point at the U.S.-Canada border.

On December 18, 2002, the CFTC announced that it had reached a $5 million settlement with Dynegy and West Coast Power LLC. The settlement stated that Dynegy had "knowingly submitted false information to the reporting firms in an attempt to skew those indexes to Dynegy Marketing & Trades' financial benefit."

On January 26, 2003, Michelle Valencia, a former senior trader at Dynegy, was indicted on federal charges of giving false data to *Inside FERC* by the Office of the United States Attorney in Houston. She was charged with three counts of false reporting under the Commodity Exchange Act as well as four counts of wire fraud. She pleaded not guilty.

On October 22, 2002, Staff sent a data request to the 10 largest natural gas marketers and asked a series of questions regarding their past reporting practices, any internal procedures or controls they had in place, any changes they made in those procedures, and any investigations they had in progress. Staff required those companies to investigate whether they had misreported data to the Trade Press and to provide data on actual trades and reported data so that Staff could check the accuracy of those reports. Staff also investigated reporting practices of the five companies that admitted that some of their employees provided false data to the Trade Press.

[2]The El Paso admission came in response to Staff's October 22, 2002 Data Request in Docket No. PA02-2 regarding the price reporting practices of the largest natural gas marketers in the United States.

In short, the investigations and responses to the data requests indicate that the companies had little, if any, formal procedures in place to ensure the accuracy of the data reported to the Trade Press. In fact, in some cases there were systematic efforts to bias the data reported to the Trade Press for the purpose of trying to offset the perceived dominance of Enron's input to the process, trying to benefit traders' own positions or that of their trading desk, and trying to offset the inaccuracies that other companies were reporting. In addition, even when these companies claim they were not trying to influence the published indices, Staff uncovered cases in which the data were inaccurate due to unstructured or nonexistent processes for reporting, such as calculating a "volume-weighted average" by taking the simple arithmetic average of the high and low trades, making up trades in order to come up with an average that was the midpoint of the traders' perceived range, and entering fictitious trades (both prices and volumes) in order to replicate what they had seen on EOL or other platforms.

Platts *Gas Daily* and Platts *Inside FERC* were the trade publications publishing the indices that were most widely used in the industry. *Gas Daily* published a daily price index and *Inside FERC* published a monthly index. *Gas Daily* published three daily natural gas prices for more than 100 pricing points: the absolute range, the common range, and the midpoint of the common range. Through interviews (primarily via telephone or fax) with natural gas market participants such as traders, end users, and producers, Platts reporters collect prices, dates, volumes, and sometimes counter parties for individual deals. According to Platts, it then sorts prices from low to high, looks for "outliers" (those prices that are greater than two standard deviations from the mean), cross-checks with counterparties, and calculates descriptive statistics (e.g., mean, median, variance, and range). The index price is based on this analysis.

Inside FERC published monthly price indices based on bid-week fixed-price transactions for gas flowing the entire next month.[3] Rather than calling traders on the phone as was the case with *Gas Daily*, *Inside FERC* had a standardized spreadsheet on which traders were to enter prices, volumes, and locations for all fixed-price deals during bid-week. The traders e-mailed the spreadsheet to *Inside FERC*, whose editors performed an analysis similar to the one performed by editors of *Gas Daily* to arrive at the published index.

[3]A fixed-price transaction is a bilateral deal based on an agreed upon price rather than a price based on an index or a basis differential off an index. Generally, a bid week begins 5 working days prior to the last trading day of the month, but it can vary across regions of the country. A bid-week price is the volume-weighted measure of gas prices for the following month done during the pipeline nomination period.

The investigation and responses to Staff requests for information on the data gathering process of the Trade Press were also documented in the Initial Report. However, the Trade Press asserted First Amendment protection from revealing data, so Staff was unable to get a complete picture of the process. After the Initial Report was completed, Staff collected pertinent information from the companies that provide data to the Trade Press. Having seen the process from the other side, it is clear that the information being sent to the Trade Press was subject to manipulation and the companies claim there was confusion among the traders regarding what the Trade Press was looking for (i.e., all trades, only fixed-price trades, observed trades, "feel for the market"), particularly in the case of daily indices. However, even when it was clear as to what the Trade Press was looking for (i.e., the *Inside FERC* spreadsheet), the traders often sent false data.

Staff also found that traders routinely complained to the Trade Press about the accuracy of the indices and that certain large players were, in fact, manipulating the indices. Traders report that large players leaned on the Trade Press to change indices after they were calculated. Further, some companies wrote letters to the Trade Press complaining about the methodology (e.g., not requiring counterparties from everyone), noting problems, and identifying irregularities. The editors of the Trade Press, therefore, were on notice that some of the data they were receiving could have been false. As such, sometimes they would have had to rely on their judgment and feel for the market rather than using a strict calculation.

Company-Specific Reporting Practices

As stated above, five companies (Dynegy, AEP, Williams, CMS, and El Paso) have admitted that their employees provided false data to the Trade Press, including *Gas Daily* and *Inside FERC*. Some of the companies state that they have taken disciplinary actions against those employees involved in false reporting, including termination of employment and forced resignation.

This section describes the price reporting practices for each of the five companies that have admitted to providing false data to the Trade Press. Although the details vary somewhat for each company, there are common themes throughout. The reporting was done by the trading desks and the traders themselves. There was little, if any, internal oversight by management or desk heads. In fact, in some cases, the desk heads and management were orchestrating the price

manipulation. The traders provided false data in order to (1) offset the perceived dominance of Enron's input to the process, (2) benefit traders' own positions or that of their trading desk, and (3) offset the inaccuracies that other companies were reporting.

Moreover, it is clear that the traders understood the process the Trade Press used to try to filter out false data and drew on that understanding to manipulate prices by constructing phony counterparties and by keeping their false data within the range of trading, only reporting numbers that favored their position (i.e., traders that wanted to see a high price only reported high-priced trades or inflated volumes on those trades).

Dynegy

On September 25, 2002, Dynegy announced it had discovered that 15 of its employees had engaged in reporting false data to the Trade Press. Of those, seven were fired, four were given the opportunity to resign, and four were otherwise disciplined by the company. Dynegy interviewed all of its employees who were involved in reporting trade data to the Trade Press. The results of the interviews indicated that for a number of years the Dynegy trading desks systematically reported false data to the Trade Press. Dynegy states that there is no evidence of a conspiracy among the trading desks or between natural gas and power traders, that it had no systematic method in place for reporting trading information to the Trade Press, and that it has moved the reporting function to its risk management group.

The employees who provided false or inaccurate data to the Trade Press reported both monthly (*Inside FERC* and NGI) and daily indices (*Gas Daily*). In their reports to the monthly indices, they fabricated trades to come to a predetermined average. For the daily indices, the main method of manipulation was inflating volumes of trades.

Many of the traders stated that they felt pressure from the heads of the trading desks to report inflated volumes or prices that benefited the desk's position. One trader reported that the heads of the trading desks would instruct traders to report transactions that had not actually taken place. Another trader said the desk head told him he had to inflate volumes and report false prices. The trader stated that sometime in 2000 he was told by his boss that "this is how the game is played and you need to play it too." The trader went on to say that on one occasion, he took his trading report to his boss, who "told him to go back and do the report again, make the volume 2 or 3 times greater and make the price range higher or lower" (he could not remember which).

The trader claimed that he reported inaccurate numbers for 2 months and then stopped doing so, and left the company shortly thereafter.

In addition, some of the fired and disciplined Dynegy traders stated that the way in which they reported price data was similar to the way in which it was done at their previous companies and they considered it to be "common practice in the industry."

Many traders reported that they provided a "survey" to *Inside FERC* and *Gas Daily*, whereby they found the "average" of the range of trades they observed and/or participated in and then constructed false trades to come up with the average. One trader stated that this was the same way in which he had reported prices when he was employed by another large energy trading company. Many of the Dynegy traders stated that they submitted bogus data (particularly to *Inside FERC*) because there were very few fixed-price trades, which is what *Inside FERC* used for its monthly index. In particular, one trader stated that it was "widely known" that "there were no fixed-price physical deals at some locations." In addition, traders claim that the heads of the trading desks were aware of this and pressured traders to report bogus fixed-price trades in order for Dynegy's numbers to be reflected in the indices. Many of the traders indicated that *Inside FERC* had to know what it was getting from the traders—that is, data on trades that never occurred. Specifically, one trader claimed that he provided his trades along with what he saw in the market to *Inside FERC* and that, despite the fact that the *Inside FERC* spreadsheet specifically asked for actual fixed-price trades made by the companies, "*Inside FERC* knew what they were getting."

Another Dynegy trader stated that he reported trades he saw on EOL or the IntercontinentalExchange (ICE) to both *Gas Daily* and *Inside FERC* because they "wanted to report more than a deal or two," and to show the marketplace that they were a player in it. Another trader stated that he felt implicit pressure to inflate volumes because of the "fear of bad ranking."[4]

Another Dynegy employee admitted to overreporting volumes because of expectations to do so or in response to prices that did not seem fair (e.g., those seen on EOL). This employee claimed to "make false reports in order to counteract false reports made by others" and said the reason for this practice was that this was "as much as a general attitude that we needed to fight back" because "the market got ridiculous with Enron." The investigation uncovered evidence of one

[4]Staff has not determined whether the ranking refers to the ranking of trading companies by volume of trading or the ranking of individual traders or desks within the company.

employee instructing other employees to submit false trades in order to serve as counterparty so the manipulation could not be detected by the Trade Press.

Staff also found evidence that a Dynegy trader and a trader at another company coordinated their numbers in order to report offsetting trades. In one case, for example, the Dynegy trader indicates an attempt to move the price at one trading point (Malin) down, and therefore only reported the low trades to *Inside FERC* (in the range of $12 to $12.50/MMBtu) that occurred during bid week. The other trader indicated that its actual trades were around $14/MMBtu.

In another example, the Dynegy trader and the other trader are coordinating their data reporting to *Inside FERC* for bid week at Malin and PG&E citygate—two significant natural gas trading points in the western United States. In both cases, the traders are discussing coordinating their reporting to ensure that their false numbers are included in the index calculation.

On December 18, 2002, the CFTC issued an Order saying that it had reached a $5 million settlement with Dynegy and West Coast Power LLC. The Order found that Dynegy had "knowingly submitted false information to the reporting firms in an attempt to skew those indexes to Dynegy Marketing & Trades' financial benefit."

On January 26, 2003, Michelle Valencia, a former senior trader at Dynegy, was indicted on federal charges of giving false data to *Inside FERC* by the Office of the United States Attorney in Houston. She was charged with three counts of false reporting under the Commodity Exchange Act as well as four counts of wire fraud. She pleaded not guilty.

On January 27, 2003, Dynegy issued the following statement:

> The former employee was one of seven dismissed by the company since Oct. 18, 2002, after an ongoing internal investigation, conducted by the Dynegy Board of Directors' Audit and Compliance committee in collaboration with independent counsel, discovered circumstances indicating that inaccurate information regarding natural gas trades was reported to various energy industry publications. In addition, Dynegy has disciplined seven other employees for their involvement in this activity.[5]

[5]Dynegy press release, January 27, 2003. www.dynegy.com.

Dynegy further stated that "[t]he past actions by these employees were in violation of the company's policies as outlined in its Code of Business Conduct" and that it was "committed to fully cooperating with all ongoing investigations into these matters."

AEP

On October 9, 2002, AEP announced that it had "dismissed five employees involved in natural gas trading and marketing after the company determined that they provided inaccurate price information for use in indexes compiled and published by the trade publications."[6] The inaccurate price information referred to in the October 9, 2002 announcement was for the Gulf Coast region. In response to the Staff investigation, AEP officials explained that the traders claimed to have been providing false information in order to counteract the false information being provided by marketers and traders at other companies.

On October 4, 2002, AEP began an internal investigation of its trade data reporting to the Trade Press. AEP states that it initiated the investigation in response to the September 25 revelation by Dynegy that some of its employees had reported false data to the Trade Press. AEP found evidence indicating that some of its employees had submitted false data to the Trade Press during the period from 1998 to 2002.

The traders claimed to have been instructed by their boss (the head of the trading desk) to adjust the prices and volumes of trades they had made and, in some cases, to report trades that never occurred. AEP claims that the traders indicated that they were doing this because they believed it was common practice in the industry, so their false reports were only intended to counteract false information reported by counterparties.

The traders were asked how they would know how much to manipulate the numbers they reported so as to offset what they perceived the other companies were reporting, if these companies were presumably reporting simultaneously. The traders responded that they had a feel (based on buys and sells) for the way in which the market was headed. AEP did not ask the traders whether they tried to influence the index in order to benefit their own positions. However, they did ask the traders if they ever provided information that they

[6] AEP press release, October 9, 2002.

knew in advance would be detrimental to their trading positions, and each indicated they had not.

AEP states that prior to October 2002, there was no process in place for gathering or reporting data to the Trade Press. Since its internal investigation, AEP has instructed all traders not to provide any data to the Trade Press. All trade data will go directly to the head of the Market Risk Oversight Group, who will verify that the data are accurate and then submit the data to the appropriate publications as necessary.

AEP states that it is continuing its internal investigation and cooperating with all relevant regulatory agencies (including FERC, the CFTC, and the SEC) as well as the U.S. Department of Justice. AEP further states that it has moved the market data reporting function from the trading desks to the risk management office.

Williams

On October 25, 2002, Williams announced it had learned that a few traders in its natural gas trading business provided inaccurate information regarding natural gas trades to an energy industry publication that compiles and reports index prices. Williams stated that the inaccuracies were discovered during an independent, internal review of its trading activities.

Williams hired an outside company to conduct an internal investigation of its price reporting. Williams' investigation of the West found no evidence that the daily data provided to *Gas Daily* over the phone were inaccurate. However, the investigation did find that the monthly data reported to *Inside FERC* were inaccurate. Specifically, it found that in a number of instances the volume of trades reported to *Inside FERC* exceeded the actual volume of Williams' trading activity.

In response to the Staff data request, Williams offers the following explanations for the discrepancies: (1) the belief that *Inside FERC* expected Williams to report not only transactions to which Williams was a party, but other transactions occurring during bid week; (2) the reported transaction dates do not necessarily correlate with dates in Williams' database; (3) the reported delivery points do not necessarily correlate with delivery points in Williams' database; (4) ambiguities caused by *Inside FERC*'s requirement that numbers be rounded; (5) the evolving nature of the *Inside FERC* form, which purported to narrow the categories of transactions about which information was

sought over time; and (6) *Williams' traders' reporting of inaccurate information* (emphasis added).[7]

The review found that some Williams traders manipulated the data they provided to the *Inside FERC* spreadsheet. They stated that they were doing this because significant market players (Enron and El Paso) were submitting a great deal of false trade data that were outside the range of prices that were actually trading, and they were trying to offset this false reporting. In addition, they wanted to show the Trade Press that they were players in the market. The traders also claimed that everyone in the industry, as well as *Inside FERC*, knew that this activity was taking place. They further stated that they believed the Trade Press was able to ferret out the most egregious misreporting and arrive at generally accurate priced indices. Williams has stopped reporting market price data to the Trade Press.

Williams did, however, find evidence of deliberate attempts to manipulate the published price indices in the Northeast. In each case, Williams found recorded telephone conversations indicating that editors of the Trade Press were questioning the accuracy of the trades reported by Williams' traders.

In one case, a reporter from *Gas Daily* indicates that there were very few reported trades for that trading point, so the trades reported by Williams changed the index by up to 10 cents per MMBtu. The reporter from *Gas Daily* indicates that he was getting numerous complaints about the published index price and requests counterparty information so he can cross-check Williams' reported numbers, but the Williams trader refuses to provide counterparties due to confidentiality concerns.

In another case, a trader is asked by an editor from *Inside FERC* to provide counterparties for the reported transactions that are on the high end of the reported range and appear to be questionable. The trader makes up counterparties, but when the editor cross-checks with the reported counterparties, they deny being involved in the transactions.

In addition, an analysis of the financial positions of the Williams trading desks indicates that the trading desk profited from the movement of the prices.

[7]December 13 Response at 5.

CMS

On November 4, 2002, CMS announced that it was conducting an internal review of the natural gas trade information provided to the Trade Press by two subsidiaries, CMS Marketing Services and Trading and CMS Field Services. CMS stated that a preliminary analysis indicated some employees provided inaccurate data to the Trade Press. CMS further stated that it would take appropriate disciplinary action and it would stop providing information to the Trade Press.

In its responses to Staff data requests, CMS stated that it had taken disciplinary action regarding seven employees (including firing four employees, three of whom were regional directors) following its inquiry into price reporting practices.

CMS hired an outside counsel who analyzed the accuracy of the trades submitted to *Inside FERC* from December 2000 to June 2002 for its monthly index. Of the 472 trades reported to *Inside FERC* for that period, there were 116 exact matches. The reasons for the 356 reported trades that did not have an exact match were: (1) reporting the sense of the market, (2) rounding off, (3) aggregation of small deals, and (4) reporting what they saw in the market.

The outside counsel interviewed gas traders and desk heads who reported CMS's trading information to the Trade Press. One trader stated that he perceived pressure from his desk head to report inaccurate prices (high or low) in order to affect the index price. The trader said he resisted the pressure, but on one occasion he did report false data in order to manipulate an index to favor the desk's position. According to the trader, during the winter of 2000–2001 the difference between the natural gas prices (basis differential) at two significant Midwestern trading points was unusually large. The trader's boss (the desk head) wanted him to narrow the basis differential between the two prices. The trader then reported high prices for the lower one in order to narrow the spread between the two.

Another trader said that the same desk head asked him to create a spreadsheet with fictitious trades designed to narrow another basis differential. The trader claims that he did create such a spreadsheet to send to *Inside FERC* and e-mailed it to the desk head.

There are many financial products traded by energy companies that are based on the basis differential between two natural gas delivery points. Companies use financial swaps and other instruments to mitigate risks

they face due to the differences in prices at various delivery locations. They also trade basis differentials in order to speculate on those differences. Because companies are taking positions based on the difference between two points, they can profit if they can affect the basis differential by moving one of the prices up and/or moving the other price down. Staff has seen examples of both. One method of manipulating indices in order to affect basis differentials is to simply make up prices, as was the case with CMS. Another way would be to only report those trades that favor their positions or inflate the volumes of those trades that favor their positions.

CMS has shut down its energy trading operation, thus it no longer reports market data to the Trade Press.

El Paso Merchant Energy

On November 8, 2002, El Paso Merchant Energy (El Paso) announced it found evidence that one of its employees had misreported trade data to the Trade Press. El Paso informed Staff that the employee refused to talk about the incident to company attorneys and resigned from the company on November 12. El Paso states that on November 30, 2001, an employee of *Inside FERC* questioned the accuracy of certain trade information submitted by that same El Paso employee.

On December 2, 2002, the Office of the United States Attorney in Houston indicted Todd Geiger, a former vice president of El Paso Energy, on charges of false reporting and wire fraud in connection with his reporting of false trades to *Inside FERC* on November 30, 2001 to be part of the calculation for the December 2001 monthly price index for the Sumas trading point at the U.S.-Canada border. On December 9, 2002, Mr. Geiger pleaded not guilty to the charges.

El Paso provided FERC Staff with recordings of telephone conversations between El Paso employees and an editor of *Inside FERC*. The tapes are telling in that the *Inside FERC* editor was trying to convince the El Paso traders to provide counterparties for all the trades they report in order to "true-up" the index. He explained that unless everyone provides counterparties, traders can submit false data with no way of being detected as long as the trades are not too far out of line with the market. He also explained that once everyone knows that the other traders are reporting counterparties, everyone will know they must provide accurate data reflecting only fixed-price deals made during bid week.

El Paso analyzed the accuracy of its reported data for its Western trading desk by comparing what was reported to the Trade Press with the actual deals captured in its information system for 728 fixed-price trades that took place between October 2000 and December 2001. El Paso found that approximately 80 percent of the transactions they analyzed were perfectly matched, meaning the price and volume reported were exactly the same as the actual price and volume. Of the 20 percent (145 trades) that were not perfect matches, 23 reported transactions had the same price but a volume different from the actual transaction. El Paso explains that 115 of the remaining 122 trades were within 5 percent of the high and low trading range of the NYMEX during the 3-day period comprising 2 business days prior to, and the day of, the NYMEX settlement for each particular month, plus the published basis index for that month at a particular pricing location.

An analysis of El Paso's reporting for the rest of the country (the Northeast, Mid-Continent, and Gulf trading desks) shows far less accuracy in the reporting than in the West. As shown in Table III-1, the percentage of exact matches between actual trades and reported trades was 1.2 percent, 1.0 percent, and 0.5 percent for the Northeast, Mid-Continent, and Gulf trading desks, respectively. That is, for these regions, approximately 99 percent of the reported trades did not represent actual trades conducted by El Paso.

The volumes of the trades are also shown in Table III-1. For these three trading desks for the period July 2000 through December 2001, El Paso traded 640,568,790 MMBtu of fixed-price physical gas. For illustration, if the average price of the gas were $4/MMBtu for the period, then the value of the gas would be approximately $2.5 billion. So, El Paso misreported 99 percent of the prices on trades worth over $2 billion. In addition, as discussed earlier, the published indices are the basis for billions of dollars of financial derivative contracts as well as physical and financial electricity contracts.

On January 13, 2003, El Paso updated its disclosures regarding price reporting to the Office of the United States Attorney in Houston. El Paso disclosed that it had found further instances of inaccurate reporting to the trade publications. On January 16, 2003, representatives from El Paso and the outside counsel performing the investigation briefed Commission Staff on its findings.

The investigation uncovered evidence that indicated there was systematic price manipulation occurring at El Paso. Specifically, prior to October 2000, El Paso reported data according to its "book bias." Staff understands that "book bias" refers to El Paso's trading position. In other words, in reporting according to the book bias, if El Paso had a long position it would report high prices and if El Paso had a short

position it would report low prices. That is, it was trying to manipulate the published price index in order to favor the company's financial position.

Table III-1. Price Reporting Summary, July 2000 – December 2001

	No. of Deals	Percent	Absolute Volume	Percent
Northeast				
Price in range but no deal match	368	84.8%	154,197,500	82.1%
Price equal to or less than 1%	40	9.2%	20,900,000	11.1%
Deal found but price and/or volume do not match	0	0.0%	0	0.0%
Deal price and volume match	5	[illegible]	[illegible]	[illegible]
	413	95.2%	178,585,000	95.1%
Price greater than 1% and equal to or less than 5%	15	3.5%	7,440,000	4.0%
Price greater than 5% and equal to or less than 10%	5	1.2%	1,550,000	0.8%
Price greater than 10%	1	0.2%	310,000	0.2%
	21	4.8%	9,300,000	4.9%
	434	100.0%	187,885,000	100.0%
Mid-Continent/Midwest				
Price in range but no deal match	388	74.3%	211,827,000	77.9%
Price equal to or less than 1%	65	12.5%	31,407,000	11.6%
Deal found but price and/or volume do not match	7	1.3%	2,786,000	1.0%
Deal price and volume match	5	[illegible]	[illegible]	[illegible]
	465	89.1%	247,539,000	91.1%
Price greater than 1% and equal to or less than 5%	54	10.3%	23,382,000	8.6%
Price greater than 5% and equal to or less than 10%	3	0.6%	930,000	0.3%
Price greater than 10%	0	0.0%	0	0.0%
	57	10.9%	24,312,000	8.9%
	522	100.0%	271,851,000	100.0%
Texas/Gulf Coast/Southeast				
Price in range but no deal match	1,065	81.5%	546,347,090	85.3%
Price equal to or less than 1%	94	7.2%	35,728,000	5.6%
Deal found but price and/or volume do not match	8	0.6%	2,140,700	0.3%
Deal price and volume match	8	[illegible]	[illegible]	[illegible]
	1,173	89.8%	585,805,790	91.5%
Price greater than 1% and equal to or less than 5%	114	8.7%	46,565,000	7.3%
Price greater than 5% and equal to or less than 10%	19	1.5%	8,198,000	1.3%
Price greater than 10%	0	0.0%	0	0.0%
	133	10.2%	54,763,000	8.5%
	1,306	100.0%	640,568,790	100.0%

Based on information available as of January 9, 2003.

In October 2000, El Paso reported accurate numbers but the evidence indicates that El Paso desk heads, traders, and management considered whether to continue reporting accurate numbers or go back to reporting the book bias. The evidence shows that many of the traders, desk heads, and managers recommended going back to reporting the book bias. The data in Table III-1 strongly suggest that for those regions, El Paso did indeed go back to reporting its book bias for the period from November 2000 to December 2001.

El Paso states that it has stopped reporting trading information to the Trade Press.

Staff Reaction to the Admissions of False Reporting

Staff expressed concerns about the accuracy of the published price indices in its Initial Report. At that time we had no conclusive evidence that anyone had actually manipulated the published price indices. We argued that, due to the generic problems with the price reporting process and problems specific to the California Border gas indices, many companies had the incentive and ability to manipulate the indices. The admissions (described above) by five significant energy trading companies (Dynegy, AEP, Williams, CMS, and El Paso) confirm our concerns. Particularly troubling is the common theme that because everyone knew that everyone else was manipulating the indices by reporting false prices and volumes, it was somehow acceptable and even necessary for this to take place. Whether the intent was to influence an index in order to favor its positions or to somehow offset the false information being provided by others, the traders of these companies were deliberately manipulating the published price indices by providing false data to the Trade Press. In addition, in many cases the heads of the trading desks were aware of the manipulations; in some cases, they were orchestrating the manipulations.

Many traders said they were attempting to manipulate the index prices in order to offset the attempts at manipulation by others. The AEP traders were asked if they ever provided information that they knew in advance would be detrimental to their trading position, and each indicated they had not. The obvious followup question, which was not asked by AEP (or at least not reported by AEP), is whether they ever provided information that they knew in advance would be good for their trading position. In general, the traders from the companies that

admitted to providing inaccurate data said they were doing so in order to ensure that their positions were reflected in the indices and that they were seen as a major player in the markets. In particular, the CFTC has concluded that Dynegy was knowingly submitting false information to the reporting firms in an attempt to skew the indices to favor its own position. Staff concludes that the most likely scenario is that traders were manipulating price indices not to help create accurate indices by offsetting the inaccuracies of others, but, to the extent possible, to move the indices in a direction that favored their positions and create the illusion that they were key players at particular locations.

The responses also indicate that price index manipulation was part of the price formation process. The indices are supposed to be based on fixed-price trades. Traders manipulated the indices by reporting false and inaccurate data on their fixed-price trading activity. Any resulting inaccuracy in the published price index fed back into the markets. Staff interviews with traders indicate that traders looked at prices in *Gas Daily* every day, just as they watched the activity on EOL. The previous day's index price served as an indicator of the opening trading price. In addition, manipulation of the daily indices would feed back into the monthly indices because monthly and daily gas are, to some extent, substitutes for each other. Moreover, trends in daily prices (especially late in the month) provide price information for next month's gas.

One of the arguments made in defense of the price index reporting process and the accuracy of the indices is that, because there are entities with the ability and incentive to manipulate the indices in both directions, the manipulation is offsetting and therefore the indices are accurate. Staff does not find this argument to be persuasive.

First, there is no reason to conclude that all of the manipulation is exactly offset. For example, many of the entities with the most influence on the indices are on the same side of the market (that is, they want to see the price move in the same direction). Specifically, some of the large purchasers of natural gas at the southern California border bought gas at fixed prices but sold it at an index price. The entities that bought gas at an index price would not be able to influence the price, but those that bought at a fixed price would have the incentive and ability to increase the index price.

In fact, six large natural gas buyers (Coral, Duke, Dynegy, Mirant, Reliant, and Williams) provided data from 18,320 natural gas transactions in California during the period from October 2, 2000 to June 22, 2001.[8] During that time the generators' fixed-price purchases

[8]Reishus and Wang Data filed under EL00-95.

were, on average, $0.30/MMBtu less than the published price indices for southern California.[9] During the period they paid $46.8 million less for their fixed-price purchase than they would have paid if they had purchased the gas at the index price.

Table III-2 shows that in December 2000, a month with extremely high and volatile natural gas prices in California, fixed-price purchases were, on average, $0.78/MMBtu lower than the published index, which is supposed to be based on fixed-price trades.

Table III-2. December Southern California Average of (Spot Price – Published Index)

	Fixed Price Transactions	Indexed Price Transactions
Buys	-0.78	-0.11
Sells	0.30	-0.22

Second, it is unrealistic that the traders could use their feel for the market (as described by the AEP traders) to predict the direction and magnitude of the other traders' manipulations and calculate a perfectly offsetting manipulation of their own. Staff finds that argument to be preposterous. As stated by the Trade Press on numerous occasions, the only way to ensure accurate index prices is to provide counterparties to all trades so they can be cross-checked, thus forcing the trading companies to provide accurate data (unless they are colluding) or have it thrown out by the Trade Press.

Third, Staff cannot recommend relying on such a haphazard method—hoping that the editors of the trade publications can perform some kind of alchemy and arrive at accurate prices despite deliberate manipulation and no systematic method of reporting the data to the Trade Press. Since the Commission has jurisdiction over most of the transactions that form the basis for the indices and many Commission-jurisdictional transactions (both gas and electric) are based on the indices, it needs to be sure that the published indices are accurate, not subject to manipulation, and not serving as a means for price manipulation. As the agency of the U.S. Government with the statutory obligation to ensure just and reasonable electricity rates, the Commission cannot rely on a recipe of offsetting false reports, traders' feel for the market, and editorial judgment (subject to claims of First Amendment protection) for accurate price indices.

The conversations between the editor of *Inside FERC* and the El Paso traders show the inherent flaws in the system. In those conversations

[9] In addition, their index-priced transactions were, on average, $0.10/MMBtu lower than the published index prices.

(which took place in late 2001, after the California energy crisis), the *Inside FERC* editor is clearly trying to obtain the most accurate data possible. This is consistent with Platts' assertion that it tried to publish the most accurate indices possible. However, the fact that the industry was not providing counterparties by late 2001 shows that the indices were still subject to manipulation. Without counterparty information, there was no way for the Trade Press to cross-check for accuracy of the reported trades. Platts and other companies that publish indices have made improvements in their data-gathering process in the last few months. In addition, energy trading companies have expressed a willingness to provide complete and accurate data, including counterparty information. It is clear to Staff that without counterparty information from all parties providing trade data, the published indices cannot be counted on to be accurate and free from price manipulation.

Even with counterparty information, price indices could be manipulated through collusion by (1) engaging in wash trading, which, as described in Chapter VII, occurred on numerous occasions during 2000 and 2001; or (2) arranging with another company to submit false information in order to provide phony counterparties. Therefore, providing counterparty information is a necessary, but not sufficient, condition for price indices that are accurate and free from manipulation.

The Commission's vision is to ensure dependable, affordable energy through sustained competitive markets. The basis for using markets to set energy prices rather than cost-of-service regulation is the belief that competitive markets can more efficiently allocate scarce resources. In a properly functioning competitive market, the market price serves to allocate resources. The price represents the value of the resource to society, reflecting demand and supply conditions. The price sends a signal to potential suppliers considering expanding production or entering the market; to the financial industry considering whether to finance such expansion, and, if so, at what interest rate; to consumers making short-term decisions regarding how much energy to consume at a given time and long-term decisions such as whether to buy an energy-efficient furnace or a gas or electric appliance; and to energy-intensive businesses regarding where to locate and which energy source to use. The price also signals where infrastructure improvements are most critical. A manipulated price sends a false price signal and misallocates resources.

The accuracy and integrity of the market price are especially critical in capital-intensive industries such as natural gas and electricity. Moreover, as the predominant input choice for new electricity generation, the accuracy and integrity of natural gas prices are

particularly critical. The decision of whether and where to build a natural gas-fired generation facility is distorted if the natural gas price has been manipulated, which leads to long-term misallocation of critical resources and ultimately hurts consumers. Accurate natural gas prices that are free from manipulation are the cornerstone of competitive natural gas and electricity markets.

In addition, the published price indices serve as the basis for a huge volume of financial derivative trading. Energy companies that serve customers use financial markets to hedge the risk in the energy industry, which is significant due to inherent price volatility and the need to make long-term decisions with little certainty regarding future prices. When index prices are manipulated (up or down), financial derivative products are not priced properly, market participants lose faith in financial markets, and the cost of risk management is increased. Ultimately, energy consumers are hurt by the increased costs and inability of energy companies to properly manage risk.

Responses to the October 22, 2002 Data Request

On October 22, 2002, Staff sent a data request to the largest natural gas marketers and asked a series of questions regarding past reporting practices, any internal procedures or controls they may have had in place; any changes they have made to those procedures; and any investigations they have in progress.[10] Staff required those companies to investigate whether, in fact, they had misreported data to the Trade Press and to provide information on actual trades and reported data so that Staff could check the accuracy of those reports.

This section describes the price reporting practices of seven of the largest natural gas marketing companies in the United States. The practices for reporting information to the Trade Press varied across companies, but there are common themes across companies. In most cases, the reporting was done by the trading desks and the traders themselves; there was little, if any, internal oversight by management or desk heads. In fact, in some cases, the desk heads and management were orchestrating the price manipulation. The traders claim they provided false data in order to (1) offset the perceived dominance of Enron's input to the process, (2) prove that they could affect the published price indices, (3) offset the inaccuracies that other

[10]Of these ten, three (Dynegy, Williams, and AEP) had already received data requests and/or subpoenas from Staff under Docket No. PA02-2 regarding their price reporting practices.

companies were reporting, and (4) replicate the prices they perceived to be the true range and average of the market. Staff concludes that, at least in some cases, the false reporting was done to favor the traders', desks', or companies' financial position. In fact, the CFTC has concluded that Dynegy "knowingly submitted false information to reporting firms in order to skew those indices to Dynegy Marketing."

In some cases, the traders understood the process the Trade Press used to try to filter out false data and drew on that understanding to manipulate the prices by constructing phony counterparties and keeping the false data within the range of trading, but only reporting numbers that favored their position (i.e., traders that wanted to see a low price only reported low trades or inflated volumes on those trades). In some cases the traders claim they were unsure of what the Trade Press was looking for, so they would report a mix of real trades, observed trades, and fabricated trades that reflected their sense of market conditions.

Duke Energy Trading and Marketing

Duke Energy Trading and Marketing (Duke) performed an analysis of the correlation between the data reported by its Salt Lake City office (West trading desk) to the Trade Press and the actual trade data recorded in Duke's database for its western United States transactions. The analysis found that for monthly transactions, 95 percent of the reported trades matched the recorded trade on price, 93 percent matched on volume, and 92 percent matched on both price and volume. For daily transactions reported to the Trade Press, 88 percent of the reported trades matched the recorded trade on price, 82 percent matched on volume, and 78 percent matched on both price and volume. Stated another way, 8 percent of the reported monthly trades were inaccurate in terms of price, volume, or both, and 22 percent of reported daily trades were inaccurate in terms of price, volume, or both.

Duke interviewed its Salt Lake City traders to try to understand why there would be occasions when the recorded trade and the reported trade did not match completely. The reasons offered by the traders included (1) some small-volume trades were excluded from the reporting, (2) some trades occurred after the office's reporting deadline of 1:00 p.m. (Mountain Time), (3) the inadvertent failure to attach a list of online trades to the form that was faxed to the Trade Press of daily gas indices, (4) a trader's use of "an eyeball estimate" of a weighted average price for transactions that were reported on an

aggregated basis, and (5) a trader's reporting of an intracompany trade that was normally excluded. Duke concludes that for the vast majority of its trades, the Salt Lake City office reported its actual transactions to the Trade Press and there was no trader intent to manipulate the indices.

Duke did not perform a similar analysis for its eastern United States transactions because "DETM's Houston office reported to the Trade Press data for indicative transactions on broader market information than just its transactions."[11] That is, because Duke reported trades that it observed in the marketplace, it would not be expected that the reported data would correlate highly with recorded transaction data.

In addition, Duke provided Staff with electronic records of the spreadsheets it used to record the range of trades and volume-weighted average that it sent to *Gas Daily*. Examination of these spreadsheets shows that Duke calculated its volume-weighted average by taking the simple arithmetic average of its high and low trades for the day. Therefore, even if the Duke traders were trying to report accurately, they were not. Calculating a volume in this manner would not create a systematic bias in either direction (that is, tending to systematically overstate or understate the volume-weighted average); it provides another source of inaccurate price data that is reflected in the published price indices.[12]

Duke did find significant inaccuracies in its reporting by the Mid-Continent, Gulf, and East trading desks, all located in Houston. Unlike traders in Salt Lake City, who reported on actual trades, the Houston traders reported their "sense of the market." The reporting was done by the physical gas traders, who generally received the data from management and the financial traders. The investigation has found that the management and financial traders sometimes biased the reported numbers to favor the trading desk's financial position.

Duke contends that by providing a "sense of the market," the traders thought they were providing what the Trade Press was looking for. Staff finds this argument unpersuasive because, for monthly prices, *Inside FERC* was explicit in its description of what it needed for its monthly index—actual fixed-price physical natural gas trades, not a "sense of the market" or basis or financial trades.

[11] Duke response to October 22 Staff Data Request, November 8, 2002.

[12] If the distribution of prices was perfectly symmetric about the mean price, then the volume-weighted average would be equal to the simple average of the high and low trade. There is no reason to believe that would be the case with any regularity.

Duke states that most of the senior management in the Houston office, including all who participated in the inaccurate reporting, are no longer with the company.

Duke states that its internal review indicates that the process of reporting natural gas market data to the Trade Press was informal. Duke claims that much of the informality was due to a general lack of understanding by Duke regarding what the various publications were seeking. Duke states that it has implemented new compliance procedures, under the direction of its chief risk officer, to ensure the accuracy of the data reported to the Trade Press.

Coral Energy

Coral Energy (Coral) interviewed all employees who provided data to the Trade Press. Coral has concluded that "the information it provided to the Trade Press accurately reflected then current market information." Coral described the type of information each trader (or other employee that provided trade data) gave the Trade Press. For both daily and monthly data, many Coral traders provided prices and volumes of (1) actual trades they had entered into, (2) trades they heard had taken place in the market, and (3) trades they had seen on trading platforms, including EOL.[13]

Coral does not address the seemingly obvious problem with reporting prices and volumes of trades that traders had "heard about" or "seen on electronic trading platforms." If a trade on EOL was witnessed by 100 traders, that does not mean the trade happened 100 times. However, if the industry practice was to report prices and volumes of trades that had been observed or heard about, then trading volumes were overstated and those trades made on EOL (the most widely observed trading platform) carried undue influence on the published price indices. Staff described the influence of EOL in the gas market price formation process, especially the Southern California Border daily market, in the Initial Report. The fact that traders were reporting trades they saw on EOL, sometimes misrepresenting them as their own trades, is another way EOL influenced the published indices. As stated throughout this chapter, many large traders used the same sort of "survey" reporting described by Coral.

[13]Some Coral traders only provided data on trades they had actually made.

Mirant

Mirant was the largest natural gas marketer in 2001, as measured by total value of trades. Mirant states that prior to September 2002, it had no formal or consistent process in place for communicating wholesale natural gas transaction data to the Trade Press. Mirant did not have any internal policies, spreadsheets, or directives with respect to the form or type of information that was being communicated to the Trade Press. Natural gas traders provided natural gas transaction information, generally over the telephone and through e-mail and facsimile, based on questions asked by various Trade Press representatives.

Mirant's Office of General Counsel and Office of Internal Audit investigated Mirant's practice of reporting information to the Trade Press for the period January 1, 2000 to October 15, 2002. Mirant's investigation team concluded that Mirant traders did not provide data that were nonrepresentative of either transactions undertaken by Mirant or actual market conditions.

Mirant did find that traders often reported transactions they had seen in the marketplace rather than only reporting its own fixed-price trades, but they believed they were reporting in good faith what was transpiring in the marketplace. Mirant's investigation indicates that the Trade Publications relied on traders that were active in the market and had access to information about the transactions of other players to provide prices from observed transactions. Mirant explains that the "observed transactions" came from computer screens provided by certain brokers and online trading platforms such as EOL and Alltrade.

Mirant found that one trader deliberately took note of "observed transactions" and reported observed prices to *Gas Daily*. That trader, who bought natural gas to serve Mirant's electric generation plants in California, had strong suspicions that the price index was being skewed upward by other trading companies that were net sellers of natural gas in California. He stated that he reported actual "observed transactions" at prices lower than he was transacting to counter the artificially high prices he perceived were being reported to push up the index price. The trader stated that he told *Gas Daily* and NGI that their published indices appeared to be nonrepresentative of the California gas market and that there were several occasions when the Trade Press did find reported trades that were not representative of the market and excluded those trades from the index calculation.

Since October 2002, Mirant has implemented a formal process for reporting information on natural gas transactions to the Trade Press. Mirant now directs all calls or contacts from the Trade Press to a designated employee in the Risk Control department who is responsible for collecting responsive data from Mirant's actual trading records for submission to the publications. Moreover, since October 2002, records are being kept as to data requested and data submitted.

BP Energy Company

BP Energy Company (BP) provided records for trading data reported to the Trade Press by fax or e-mail. BP states that during the period in question, it provided natural gas prices and transaction data to the Trade Press on spreadsheets containing information drawn or downloaded directly from the transaction support system. BP had a formal system in place for reporting transaction data to the Trade Press that included assigning the responsibility for reporting to a single trader with oversight and accountability from the trading managers.

BP could not provide records of the data reported to the daily publications over the phone. BP states that any information reported over the phone came directly from daily deal sheets. BP's internal price index reporting policy requires all discussions with third-party publications to be limited to the designated representative, with the trading managers serving as backups.

Reliant

For daily price reporting (*Gas Daily* and NGI), Reliant reported daily trading by fax to the Trade Press. Each day, traders would pass a daily worksheet around the trading floor and one or more traders would handwrite information on trading points with which they were knowledgeable. Some traders reported pricing for Reliant trades; others also reported other trades observed in the markets. At 2:30 p.m. each day, a Reliant analyst would fax the worksheet to the Trade Press. Reliant states, "[t]he worksheet was not reviewed by a supervisor or another employee before it was transmitted."[14]

Reliant used different monthly price reporting procedures at its various trading desks. It has almost no record of the West desk's reporting (it found a single spreadsheet from the Denver office). However, Reliant

[14]Reliant response to October 22 Staff Data Request at 4.

was able to locate many of the spreadsheets sent from the East trading desks (Southeast and Northeast).

Reliant's process for reporting to *Inside FERC* is particularly noteworthy. As described in this Report, Platts' *Inside FERC* had a standard spreadsheet that it required companies submitting trade data to use for reporting bid-week trades for its monthly index. The spreadsheet required price, volume, date, and company name to be entered for each reported trade. Reliant did not use actual trades to fill in the bid-week survey; rather, it used a three-part process to generate a set of fictitious trades to enter into the spreadsheet: First, the traders agreed to a "consensus" range of trades. Next, an analyst determined the midpoint of the consensus range. Finally, "the analyst would generate a list of prices—all falling within the consensus range—and volumes that arithmetically led to a weighted average at the consensus midpoint."[15]

Reliant states that it believes the method described above was not meant to influence prices; rather, it was intended to provide accurate information about market prices. In support of this conclusion, Reliant notes that the volumes reported to *Inside FERC* were often substantially lower than Reliant's actual trade volumes at the reported locations. Reliant argues that someone trying to influence the index price would tend to overstate volume rather than understate it.

Reliant compared the reported data to the actual trade data captured in its internal computer system. It found that approximately 65 percent of the reported midpoints were within 1 percent of the actual midpoint, approximately 97 percent were within 5 percent of the actual midpoint, and approximately 99 percent were within 10 percent of the midpoint. Moreover, the data support Reliant's claim that it consistently underreported the volume of its trades. Of 514 price reports for which comparisons could be made, the reported volume was less than the actual trade volume in 432 cases (84 percent). In the cases where Reliant underreported its volume, the volume reported was approximately 15 percent of the actual volume. In 84 cases (approximately 16 percent), the reported volume was greater than the actual volume—on average, approximately 100 percent above the actual volume. Reliant states that the discrepancy in volume was not surprising because traders focused on accurate prices rather than volumes.

Staff notes that accurate volumes are a critical part of calculating an accurate price index because the indices are volume-weighted averages. It is clear from the investigation that one of the ways in

[15]Reliant response to October 22 Staff Data Request at 8.

which companies tried to manipulate the published price indices was by reporting inaccurate volumes—both by overstating volumes of trades that favored their position and by understating volumes of trades that hurt their position.

Sempra

Sempra Energy has three affiliates—Sempra Energy Trading (SET), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric (SDG&E)—that reported prices to the Trade Press. Each entity had different degrees of interaction with the Trade Press and had its own reporting procedures.

SET states that it sent e-mails to *Inside FERC* and NGI and received phone calls from *Gas Daily* and Btu.[16] SET states that no record exists of any of the telephone conversations with *Gas Daily* and Btu. SET found only five e-mails of data submitted to *Inside FERC* and NGI for all of 2000 and 2001. SET compared actual trade data with data reported to the Trade Press for the small subset of reported trades for which it had records, and found no discrepancies. SET states that it has learned of some minor discrepancies ($0.01 to $0.02/MMBtu) in the data reported to *Gas Daily* on a few occasions involving an area in the Rocky Mountain region.[17] SET explains that both *Inside FERC* and NGI requested written transaction information via fax or e-mail for their monthly indices. With respect to *Gas Daily*, there was no formal reporting practice. As was the case with other energy trading companies, SET employees were sometimes asked by *Gas Daily* to report or comment on general market conditions and/or other trades they may have been aware of. SET states that "Responses to such requests varied. Some employees refused to comment on trades not executed by SET. Others reported their knowledge of various trades in the market based on data available on electronic trading platforms (such as ICE)."[18]

SoCalGas unequivocally states that no employee provided inaccurate data to the Trade Press. They provided written records of the trades but state that there is no way to check on them because they were reported over unrecorded phone lines. SoCalGas also states that it is required by the California Public Utilities Commission (CPUC) to submit all of its trade data to the CPUC and that it provides the same data to the Trade Press that it provides to the CPUC. In addition, SoCalGas provided

[16]Btu Publishing Inc. publishes energy market information and price indices in its publications: Btu Weekly, Btu's Daily Gas Wire, and Btu's Midday Report.
[17]SET response to October 22 Staff Data Request at 2.
[18]SET response to October 22 Staff Data Request at 3.

Staff with spreadsheets identifying all spot market transactions for 2000 and 2001; the spreadsheets indicated if the transaction was a purchase or sale, price, volume, and counterparty. These data were the same as the data submitted to the CPUC.

SDG&E states that it was not a significant natural gas trader and, as such, its employees provided prices and volumes to the Trade Press on a limited number of occasions. SDG&E states that no employee provided any inaccurate information to any entity publishing price indices. SDG&E further states that as a regulated California public utility, it provides monthly reports to the CPUC's Energy Division and to the CPUC's Office of Ratepayer Advocates, providing details of all its physical and financial natural gas transactions.

Aquila Merchant Services

Aquila Merchant Services (AMS) states that it had three trading desks: West, East, and Mid-Continent. It reported daily trading data to *Gas Daily* and monthly data to *Inside FERC* and NGI; daily trading data were reported by fax. Each day traders would pass a form (the Aquila Energy Marketing *Gas Daily* Pricing Log) around the trading floor and one or more traders would handwrite information on trading points with which they were knowledgeable. AMS would report the range of trades, midpoint, and volume. AMS states that although the desk head was ultimately responsible for the information sent to *Gas Daily*, it appears that any trader could enter data onto the form. Interviews with traders indicate that some traders provided only actual AMS trades while others reported a combination of trades they saw on electronic platforms (such as EOL) and actual AMS trades. Traders indicate that there was some uncertainty over the specific data *Gas Daily* wanted, that is, whether *Gas Daily* wanted only actual trades or more of a market survey.

For monthly reporting, AMS employees reported trade data by e-mail on a spreadsheet that was stored on a shared drive. As with daily reporting, although the desk head was ultimately responsible for the information sent to *Inside FERC* and NGI, it appears that any trader could enter data onto the form. In compliance with Staff's data request, AMS analyzed the accuracy of the reported monthly prices by comparing the actual trade data with the reported trade data. AMS found that the data reported by the West desk were accurate, but the data reported by the East and Mid-Continent desks showed discrepancies for January, February, March, April, and June 2000. In one case, a trader stated that the desk head provided a range of prices that he knew were not based on real prices and a volume-weighted

average price that he knew was not accurate, and gave instructions to fill in fictitious numbers within the false range on the spreadsheet to arrive at the false weighted average. The trader stated that this practice stopped after October 2000, when AMS instituted a practice of reporting counterparties for every trade and only reporting fixed-price trades.

The evidence suggests that the attempt at price manipulation was not done specifically to offset the misreporting of other companies, but there was a general sense among the traders and desk heads that other companies (including Enron) were attempting to manipulate the published indices to their financial advantage and hurting AMS. One trader described it as a Prisoners' Dilemma,[19] that is, given what the other large trading companies were doing (reporting false data to favor their positions), his best response was to report false prices even though everyone would be better off with accurate price indices.

AMS states it had concerns with the price reporting methodology and it perceived that others were manipulating the indices. Through interviews with traders, desk heads, and former AMS managers, it found specific accounts of AMS employees contacting the Trade Press to question the accuracy of the published indices when AMS employees did not believe the indices were representative of market conditions. AMS provided copies of letters sent by its General Manager to Financial Times Energy and *Inside FERC* regarding the methodology used to compile its indices and advocated accepting only trade data from companies that have agreed to be audited.

In August 2002, AMS announced that it was shutting down its wholesale marketing and trading operations. By the end of the third quarter of 2002, AMS had eliminated most of its wholesale marketing and trading business, including market making activity and speculative trading. By the end of the fourth quarter of 2002, AMS had unwound almost all of its energy trading positions. AMS states that it has eliminated most of its positions in merchant operations and most of its employees, and no longer reports trade information to energy industry publications such as *Gas Daily*, *Inside FERC*, or NGI.

[19] In the Prisoners' Dilemma, two prisoners must decide separately whether to confess to a crime; if only one prisoner confesses, he will receive a lighter sentence and his accomplice will receive a heavier one, but if neither confesses, sentences will be lighter than if both confess. The individual incentives faced by both prisoners force them to confess, even though they would both be better off if they did not. The outcome (mutual defection) is an example of a Nash Equilibrium in game theory. See, for example, Robert S. Pindyck and Daniel Rubinfeld, *Microeconomics*, 5th edition, pp. 442-444.

Staff Reaction to Responses to the October 22, 2002 Data Request

The answers to the questions in the October 22, 2002 Data Request show that the industry lacked systematic reporting procedures and internal verification processes.[20] The responses also show that the price manipulation goes beyond the five companies that have admitted to such behavior.

As noted above, most of the largest natural gas marketing companies in the country had no formal process for reporting trade data to the publishers of the price indices; the process was left to the trading desks and the traders themselves. Traders from all companies describe a typical trading day as hectic, pressure packed, and frenetic. One of their many tasks was to report trading data to the Trade Press; this was viewed as bothersome but necessary. Often it was a job given to the newest employee. Many companies report passing around a form or using a spreadsheet on a shared drive. The last person who filled out the form or spreadsheet may have been required to total the numbers and send them to the Trade Press. There was nothing to stop a trader from changing the numbers someone else had entered. In other cases, traders took an oral "survey" to get a sense of where the market was trading. Sometimes they represented it to the Trade Press as an actual survey, but in other cases they made up trades to average out to a number that was consistent with this "survey."

Although *Inside FERC* did have a spreadsheet and requested data on fixed-price deals transacted during bid week only, it is clear that the companies were reporting a combination of fixed-price deals during bid week, trades observed on EOL, and trades they made up to reach a predetermined average.

The process for reporting daily prices was more chaotic than the process for the monthly indices. Again, the responses show that traders reported some combination of actual trades, trades they observed, and trades they made up. Some traders reported a range of prices and some reported an average. Sometimes the average was volume weighted; at

[20]BP Energy is a notable exception. It is clear from BP's response to the Staff data request that it recognized the influence a significant trader such as itself could have on the published indices. BP put internal controls in place to ensure the accuracy of the reported data and a employed a system of accountability for the trading desk heads.

other times it was the simple average of the high and low trades. Some traders received phone calls, some called the Trade Press, and some faxed prices and volumes. Staff inspection of the faxes shows that there was no standardization of the data reported to the Trade Press. In some cases volumes and average prices were reported, some had individual trades, some showed basis differentials, and some were financial rather than physical deals. Because most of the reporting was done by phone, there are significant barriers to finding out what the traders actually reported to the Trade Press. As with *Inside FERC*, the editors of *Gas Daily* assert First Amendment protection, so there is no way to ascertain what they were told and their awareness of the extent of the manipulation. Moreover, the companies themselves were unable to re-create their daily reporting because (1) it was done by phone and the phone calls were not always recorded (even if they were recorded, it would take thousands of hours to listen to the recorded calls) and (2) the Trade Press denied companies' requests for their own data, citing confidentiality and First Amendment protection.

In short, the responses indicate that the reported price indices were based on data that were confusing, inaccurate, misleading, and often false. Staff concludes that an accurate index could not have resulted from the data that were reported. In addition, because the Trade Press has not revealed their data, there is no way to verify the accuracy of the reported indices by comparing them with the data reported to the Trade Press.

Staff Attempts To Verify the Accuracy of the Reported Indices

As part of the investigation, Staff attempted to verify the accuracy of the reported price indices; however, there have been significant barriers to this process. First, in many cases the companies cannot reproduce the data they reported to the Trade Press for the reasons described above: daily reporting was done by phone, often on unrecorded lines; many traders reported their own trades along with those they observed in the market; and records of the reported data were not maintained because there was no formal process for reporting the data. In addition, the Trade Press has not revealed the data used to calculate the indices.

One of the issues that became apparent to Staff while investigating Enron and other energy traders is that they lack many business records that are essential when investigating allegations regarding trading activities. Because the companies have argued that their trading

activities are not jurisdictional to FERC, CFTC, or SEC, many fail to keep records that would be required of a regulated company. For example, maintenance of phone tape recordings can be haphazard at these companies. Staff found evidence indicating that Enron had received a legal opinion finding that their 4-month tape retention policy was not in compliance with FERC regulations. During the same time that Enron received this finding, they were reducing their retention to 30 days. Although the retention of phone tapes in the power industry is an accepted practice, the length of retention varies. Specifically, the lack of record keeping, especially recorded telephone conversations, made it difficult and, in some cases, impossible to verify the data provided by the companies to the Trade Press.

As described earlier in this chapter, Staff analyzed the trading data of six major gas purchasers in California and compared them to the published price indices. The analysis uses data submitted under Docket No. EL00-95 by David Reishus and Patrick Wang of Lexecon Inc. on behalf of five companies involved in that proceeding (Duke, Dynegy, Mirant, Reliant, and Williams). The database they used included spot transactions from six companies: Coral, Duke, Dynegy, Mirant, Reliant, and Williams. Staff found that for those six companies during that period, their fixed-price purchases were systematically lower than the published index prices (which are supposed to be based on that type of transaction only).[21]

Industrywide Reporting Issues

As described in the Initial Report, the industry relies on both daily and monthly natural gas price indices. The monthly price indices are based on fixed-price transactions occurring during bid week. During the course of the investigation, it became clear to Staff that transactions occurring during bid week do not give an accurate picture of the monthly natural gas trading activity. A number of large traders (e.g., Dynegy, AEP, and Williams) stated that they did very little fixed-price trading during bid week. They stated that they mainly traded indexed contracts or small fixed-price deals designed to fine tune their physical and/or financial positions for the month. Data provided from the large natural gas traders and marketers confirm this position. In fact, traders said that one of the reasons they fabricated the prices and volumes they provided to the Trade Press was that they had very few trades during bid week and they wanted to reflect their actual trading activity for the month. Another problem with reporting bid-week trades only is that

[21] See Table III-2 on page III-17.

the market is quite thin during this period; that is, there are fewer buyers and sellers (at least for fixed-price deals). Therefore, even if prices for trades made during bid week were reported accurately, those prices do not necessarily reflect competitive market prices.

The Testimony of Michele Markey

On November 18, 2002, Michele Markey testified before the State of California Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. According to her testimony, from May 1998 to September 2001 Ms. Markey was in charge of the gas price and electric price teams that gathered information from the industry for publishing the price indices in *Gas Daily* and *Megawatt Daily*. From her experience as a trader and her work at Financial Times Energy and Platts,[22] Ms. Markey described the energy trading process, the data gathering process at the daily and monthly publications, and the perception in the marketplace of the published price indices; she also gave examples of how an index could be manipulated. When asked by Senator Dunn if, in her opinion, it was common practice in the industry to exaggerate the prices reported to the indices, she replied: "It was common industry knowledge that exaggeration was part of the process."[23]

One of the subjects Ms. Markey addressed was that traders understood that if the prices they reported were too far out of line with real prices, they would be thrown out by the editors of the price indices. Therefore, traders would report trades that favored their positions but were within the range of actual trading. She explained that because the indices were weighted averages, traders could manipulate the index by reporting inflated volumes at prices that favored their positions:

> Common practice was to exaggerate your transactions to the price reporters, report more volume, report a higher price than that was actually transacted. You stretched your price in favor of what the company's position was, or don't report at all, because you would know whether or not your indices—your volume and price could in fact affect the index.[24]

Ms. Markey also discussed a proposal by Enron for *Gas Daily* to create an electronic platform price index. The index was designed to

[22]Ms. Markey also worked as a West desk trader for Reliant prior to her employment with Financial Times and Platts. At the time it was called Noram Energy Services.
[23]Markey testimony at 13.
[24]Markey testimony at 15.

capture all trading on electronic platforms, but ultimately captured only Enron. She testified that:

> In effect, Enron gave us the methodology and dictated to us how that price index was going to be calculated. And we set it up basically at their request.[25]

In the summer of 2001, Ms. Markey proposed that *Gas Daily* (owned by Financial Times Energy at that time) audit the data from EOL in order to ensure its accuracy. She stated that a number of energy traders complained that Enron was manipulating prices through EOL. She arranged for Price-Waterhouse-Cooper to audit the data and the contract was ready to be signed; however, in August 2001, the plan was abandoned when Platts purchased *Gas Daily*. Therefore, there was no audit of the Enron data.

On November 19, 2002, the president of Platts, Harry Sachinis, issued a statement in response to Ms. Markey's claims. Mr. Sachinis explained why Platts had rejected her proposal to publish an EOL price index and to audit the data from EOL:

> Michele Markey, who worked for Platts for only six months, implied that we quashed a suggestion to audit questionable trading data supplied by Enron because Enron was a Platts customer. This is completely false. In fact, Platts chose not to pursue Ms. Markey's auditing proposal because publishing an index based on Enron Online trading data would have little if any value to subscribers. Platts had previously declined requests by Enron to publish such an index. Platts believes that an index based on a single company's trades would be unreliable and subject to manipulation, whether audited or not.[26]

The Effect of Enron and EOL on the Published Price Indices

The issues discussed by Ms. Markey are related to some of the concerns raised by Staff in the Initial Report regarding the influence of EOL on the published price indices. As stated in the Initial Report, EOL was a significant source of price discovery in the natural gas markets. The responses to the data request confirm that many traders looked at EOL to observe market conditions. In fact, many traders

[25] Markey testimony at 39.
[26] Platts response to Markey, November 19, 2002.

actually reported trades they observed on EOL to the Trade Press; some of those traders misrepresented those trades as transactions they had made themselves. As described in this Report, EOL was a one-to-many trading platform, i.e., the Enron market maker was on one side of every trade done on EOL. The market maker established the bid and ask prices and profited from the spread between the two. In addition, the market maker had information superior to the rest of the market and had the ability to influence the price. By posting the bid and ask prices for a particular location at a given price, an Enron trader would have a greater likelihood of affecting the index price at any point traded on EOL than any other single trader. Thus, trades made on EOL could be fed into a particular index over and over, as other traders were reporting what they observed on EOL to the Trade Press. Some of the traders that attempted to manipulate the indices said that they were doing so in order to offset Enron's perceived dominance at particular trading points, particularly at Topock on the California border.

Ms. Markey proposed publishing an EOL price index and auditing Enron's reporting practices. As argued by Platts' president Harry Sachinis:

> Platts chose not to pursue Ms. Markey's auditing proposal because publishing an index based on EnronOnline trading data would have little if any value to subscribers. Platts had previously declined requests by Enron to publish such an index. Platts believes that an index based on a single company's trades would be unreliable and subject to manipulation, whether audited or not.

Staff agrees with Mr. Sachinis's conclusion that an index based on a single company's trades would be unreliable and subject to manipulation. The facts uncovered in this investigation indicate that EOL had an undue influence on the published indices, especially the SoCal Topock *Gas Daily* Index. Those facts are as follows:

1. A large percentage of the legitimate trading for SoCal Topock took place on EOL.
2. Much of the trading for SoCal Topock on EOL was between Enron and one counterparty, Reliant, which had a "netting arrangement" with Enron; this arrangement created the incentive to "churn" (see Chapter II) natural gas on EOL. Only Enron and the Reliant trader knew of the netting arrangement.
3. Many traders reported trades they observed on EOL. Some traders misrepresented those trades as their own transactions.

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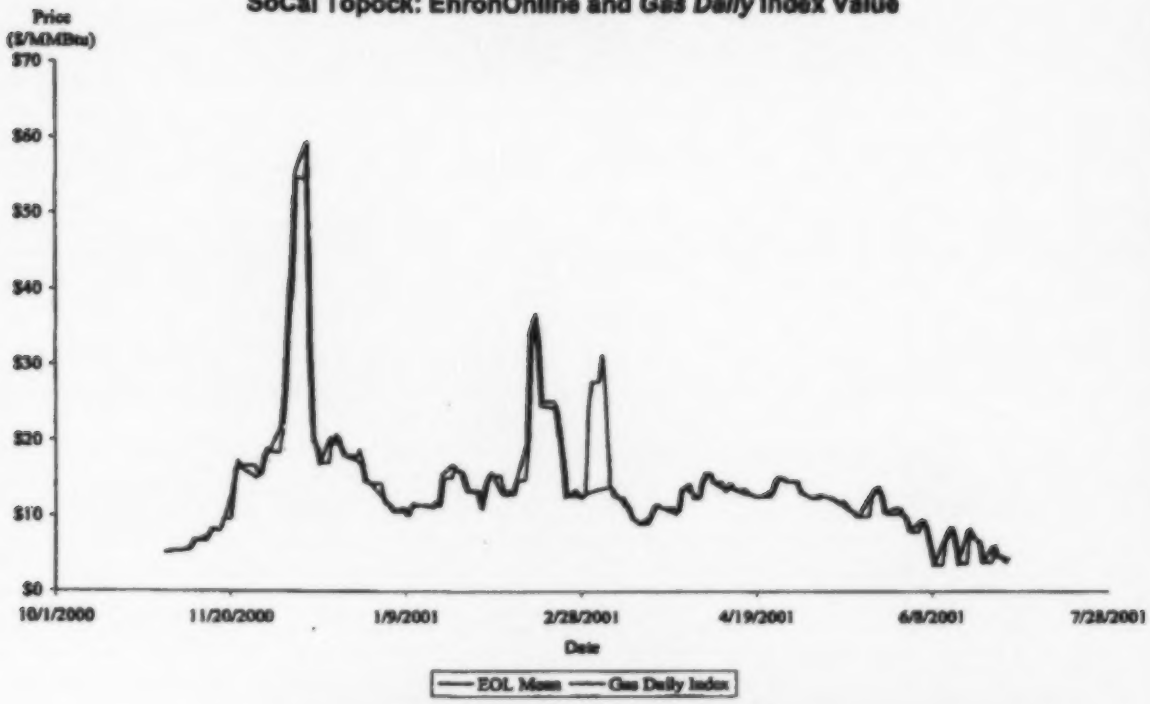
4. Traders used EOL for price discovery, so the price of off-EOL trades was influenced by EOL.

Figure III-1
SoCal Topock: EnronOnline and *Gas Daily* Index Value



As shown in Figure III-1, the *Gas Daily* price almost perfectly tracks the EOL price. In the Initial Report, Staff focused on one trading day, January 31, 2001. On that day, total trading volume at southern California Topock reported to *Gas Daily* was 6,766,000 MMBtu, which was the busiest trading point for that day. The total volume on EOL for next-day Topock gas for the day was 2,240,000 MMBtu. At the time of the Initial Report, Staff did not know the extent to which the reporting of trading volume was manipulated by the traders. The total volume of trading on EOL for the day (2,240,000 MMBtu) is actual trading verified by Staff. The total volume reported by *Gas Daily* (6,766,000 MMBtu) cannot be verified because *Gas Daily* has not revealed its data. Moreover, as described above, most companies spoke to *Gas Daily*'s editors over the phone and did not keep records of what they reported. Staff suspects that of the 6,766,000 MMBtu reported by *Gas Daily*, much of it was based on trades observed on EOL in addition to the actual trades made on EOL. Finally, as noted in the Initial Report and discussed in Chapter II, more that 75 percent of the trading on EOL that day was with one trader from Reliant. Thus, the volume reported and the observed activity on EOL give the illusion of a much more liquid market than was actually present.

As described in detail in Chapter II, the anomalous trading behavior on EOL would influence the index price because the index price was a volume-weighted average.[27] That is, even if the price returned to where it was before a flurry of buying and selling (churning), the volume-weighted average would increase because all of the buys and sells occurring during the churning were taking place at a higher price. The fact that numerous market participants were reporting what they saw on EOL only intensifies this effect.

In addition, as described in detail in Chapter IX, Staff has identified a case in which Enron traders used EOL to manipulate the Henry Hub market price. In the July 19, 2001 manipulation, the Enron market maker aggressively bought natural gas at Henry Hub to drive up the price, then aggressively sold the gas, driving the price back down, while his partners in the scheme made huge profits in financial derivative products by selling short when the price was rising, knowing that it would soon fall. Even though the price returned to its premanipulation level once the scheme was complete, the manipulation affected the index price because it is a volume-weighted average. The manipulation induced a price run-up and an ensuing fall. The trades that took place during the manipulation were all above the pre- and postmanipulation price level, thus bringing up the average. Again, the fact that numerous market participants were reporting what they saw on EOL intensified this effect.

The index prices also fed back into southern California natural gas market performance through the gas imbalance penalties on the SoCalGas system. As described in Chapter II, the penalties for imbalances on the SoCalGas system were 150 percent of the highest daily border price index at the Southern California Border for the month the imbalance is created. The highest daily border price index is an average of the prices from NGI's "Daily Gas Price Index—Southern California Average" and the *Gas Daily* "Daily Price Survey—SoCal Large Packages Midpoint Price." Therefore, a higher index price would increase the imbalance penalty, which would in turn increase the price buyers were willing to pay for gas in order to avoid the penalty.

Staff concludes that all of the concerns expressed in the Initial Report have been confirmed. These concerns include the following:

[27] See Chapter II, Reliant's Churning Raised the Index Prices, page II-30.

- The Commission cannot independently verify the published price data.
- Undetected errors may exist because trade publications reporting spot and forward prices do not employ statistically valid sampling procedures or a systematic, formal verification procedure.
- Market participants have significant incentives to manipulate spot market prices reported to the reporting firms because natural gas is the fuel input for the electricity generators that set the market price in California.
- Wash trades may have an adverse effect on reported price data.
- EOL was a significant source of price discovery and formation and was potentially susceptible to manipulation by market participants, which could affect the published price indices.

Moreover, systematic attempts to manipulate the published price indices by various significant market participants occurred for at least 4 years. Because of these events, some companies have stopped reporting trading data to the Trade Press;[28] many companies have left the trading business;[29] Dynegy settled with the CFTC for attempted price manipulation and other violations of the Commodity Futures Trading Act; some traders have been indicted on Federal criminal charges;[30] and AEP has been the subject of a class-action lawsuit.

On the positive side, there has been a movement within the industry to fundamentally reform the price reporting process. Suggestions for reform and tangible reforms have come from market participants, risk officers, the trade publications themselves, new entrants into the price reporting business, government agencies, consumer groups, and others.

On January 15, 2003, Commission Staff from the Office of Market Oversight and Investigation (OMOI) reported concerns regarding price index formation to the Commission at its public meeting. Staff explained the Commission's interest in price index formation, reviewed the public evidence that raised questions about it, defined the high-level criteria that are important to developing trustworthy price information in the future, and proposed some next steps.

OMOI Staff proposed that in the future, the Commission should require that natural gas price indices meet certain minimum requirements before natural gas pipelines are permitted to use the

[28]For example, BP Energy, El Paso, Reliant, Williams, Constellation, and PP&L.
[29]For example, Aquila Marketing Services and CMS.
[30]See El Paso and Dynegy.

indices in new tariffs or for other new regulatory purposes. Staff proposed that evidence for these new filings would need to be presented and reviewed to ensure that any referenced price index meets minimum index formation standards. In particular, the index would need to accurately reflect the market. For approval, a new tariff containing a reference to an index would need to demonstrate:

1. Confidence in the accuracy of price reporting—that is, the ability to verify that reporting is for deals actually done, not simply aggregate options.
2. Adequacy of coverage—that is, the ability to ensure the collection of adequate information to represent prices across the relevant marketplace.
3. Information about market liquidity or some insight into how much trading is going on a particular point in order to generate warnings when markets are thin and confidence when they are liquid.
4. Verifiability—that is, the ability to ensure integrity of the process through independent review by a trustworthy third party (preferably not a government entity).[31]

Reform of the Price Reporting Process

Company Changes

Most of the companies involved in natural gas trading and marketing have implemented or are in the process of implementing new procedures for reporting trading information to the Trade Press. Specifically, many companies are moving the data reporting process away from the trading desks to the risk management office. In addition, companies are using their IT systems to capture the relevant data and send it directly to the risk management office. For example, Duke's new policy is as follows:

> Transactions are captured in DETM's trading systems. System queries have been developed to extract the relevant third-party physical transactions from the source systems and generate a report. The report contains the location, price, and volume for each transaction. The mid-office receives the electronic report and reviews the data. The transactions that are submitted to the publications are validated through a combination of confirmation and trade validation control

[31] FERC OMOI Staff Report. 2003 Natural Gas Market Assessment.

> procedures. These procedures will ensure that only information about actual transactions entered into with third parties will be provided to the Trade Press publications.[32]

As noted above, many other trading companies (including Mirant, AEP, and Dynegy) are adopting similar procedures. Staff finds that the revised process for reporting the relevant trade data to the Trade Press is a significant improvement that gives credibility to the data and that it is in stark contrast to the nearly universally haphazard reporting that took place in the past.

In addition, many companies (including PP&L, BP Energy, El Paso, Reliant, Williams, CMS, and Constellation) have stopped reporting trading data to the Trade Press. This is an understandable reaction given the chaos in the industry and the legal issues facing firms that have already admitted to providing false information and those that are still investigating or are the subject of investigations as to whether they provided false information. Because the indices for commercial transactions are very important, procedures must be put in place to ensure the accuracy of the indices and to encourage (or require) all market participants to provide complete and accurate data. Staff recommends that a process for establishing standards for price reporting be established by the Commission, with input and cooperation from the energy industry and the price reporting firms. In addition, other government agencies (such as the CFTC and the Energy Information Administration) should be involved in the process. Significant progress has been made in this area since the issue regarding the accuracy of the reported indices became a subject of this investigation.

Proposal of the Committee of Chief Risk Officers

As described above, in many cases the reporting function is being moved to the companies' risk management offices. On November 19, 2002, the Committee of Chief Risk Officers (CCRO) (representing 31 energy companies) announced that it is examining how companies submit price data and what type of data are submitted and that it hopes to develop a "transparent and robust methodology" that will maintain confidentiality.

On December 4, 2002, the CCRO met with the publishers of energy price indices to discuss the attributes of credible market price indices

[32]Letter to Donald Gelinas, Associate Director, Office of Markets, Tariffs, and Rates, from Mark Perlis, Counsel to Duke Energy Trading and Marketing L.L.C., under Docket No. PA02-2, November 8, 2002.

for energy transactions. The forum was open to all companies currently publishing indices for the North American energy market. The CCRO stated that "[l]eaders of the Committee's Market Price Indices Working Group embarked on this task amid questions about how price indices for natural gas and electricity transactions have been, and are being, tabulated." The CCRO further stated that it "intends to consider information and points of view provided by the publishers' representatives to help produce draft recommendations that will lead to credible, sustainable price indices in the coming weeks."[33]

On February 27, 2003, the CCRO released its Best Practices for Energy Price Indices white paper. The CCRO white paper includes recommendations for data gathering and submission procedures, index construction processes and methodology, and necessary contractual arrangements to facilitate the recommended changes on the part of both the companies supplying market information and any entity publishing energy price indices. The white paper also recommends a formal auditing process for both the energy companies providing data and the companies publishing price indices.

Data Gathering and Submission

The CCRO recommends that data providers supply index developers with these and other data points about each trade, every day they trade:

- Buy or sell indicator.
- Volume of energy involved.
- Flow date(s) of the energy transaction.
- Location of delivery points.
- Price.
- Any exchange or clearinghouse involved.
- Date the transaction was executed.
- Counterparty.

Index Construction Process and Methodology

The CCRO has the following recommendations for index publications:

- Index developers should implement robust IT and data security protections against data misuse by employees.
- Index developers should publish the index methodology, including defining (1) a sufficient sample size for normal creation of an

[33]December 2, 2002 press release: Committee of Chief Risk Officers Plans Forum to Discuss Energy Price Indices.

index and (2) the process for determining an index value where there are insufficient data.

- Index developers should ensure that the "strictest standards of care" will be maintained over commercially sensitive data. The paper also recommends that index developers audit their processes annually.

Contractual Arrangements

The CCRO recommends that before the information described above is provided, contracts should be drawn up and amended between counterparties to protect the confidentiality of the data. The CCRO encouraged data providers and index developers to sign an agreement that, among other things:

- Commits each party to a specific data-reporting protocol.
- Protects the confidentiality of the data.
- Prohibits the use of data beyond constructing an index.

The CCRO recommended that counterparty information should be submitted only after:

- Each individual with access to the data at the index developer signs a clear-cut, enforceable confidentiality agreement.
- Any index produced by a publishing organization is separated from any news-gathering operations by a verifiable and auditable "Chinese wall."

Auditing Process

The white paper recommends a formal auditing process for both the energy companies providing data and the companies publishing price indices.

The CCRO recommends that independent audits be conducted by each company publishing indices at its expense at least annually to determine the following:

- The data are properly collected and stored in compliance with all contractual arrangements with data providers, including confidentiality arrangements. Specifically, the data are properly protected from release and misuse at all levels.
- The methodology established and published by the index developer is the same as that used to calculate and publish the actual index.

- The methodology established and published by the index developer satisfies the attribute of robustness as defined by the index developer in accordance with the principles in this white paper.
- Periodic tests are conducted to verify that the process used to derive published indices is accurate, objective, and reliable.

The CCRO also recommends a formal auditing procedure for the companies submitting data for index publication:

> An independent (internal or external) audit group should review the data gathering and submission process at least annually, verifying the proper implementation of and adherence to the data gathering and submission process that the company has established. This audit should be conducted at the expense of the data provider by a qualified individual, i.e., Certified Public Accountant or Certified Internal Auditor. The pass/fail results of the audit should be made available to the index developers upon request. In the event of a failed audit, the data provider should be able to reaudit once appropriate process changes are made.

Staff commends the CCRO on its efforts to reform the index price reporting process. Although the CCRO white paper is a recommendation for best practices and not a binding commitment by its member companies, it addresses the fundamental problems in the process and provides feasible solutions. The necessary data to compile an accurate and reliable index identified by the CCRO are nearly identical to those proposed by Staff later in this chapter.[34]

The CCRO paper has directly addressed the critical pieces of information for ensuring an accurate index: providing the counterparty and buy/sell information for every trade. The paper recognizes the commercial sensitivity of such information, but proposes amending existing energy contracts to allow for its provision, provided the confidentiality is preserved by the index publishers through explicit contracts. As discussed throughout this chapter, without the ability to cross-check reported prices and volumes, the published indices will not be reliable. As noted by Platts in its February 10, 2003 call to action:

[34]It is Staff's position that one critical piece of information missing from the CCRO proposal is the time stamp of when the transaction was made. Staff understands this to be an IT issue that could be worked out. The time stamp would further aid in cross-checking transactions and assessing whether an outlier should be rejected (since prices may move significantly within a day of trading) when calculating a price index.

> Information on counterparties, buy/sell indicators and time stamps is critical to the process of verifying data. This information will help Platts in its efforts to confirm such data characteristics as completeness (by enabling publishers to detect a provider's omission of certain deals) and accuracy, and it will serve as a check against double counting. In fact, counterparty information is one of the best means for publishers to identify inaccurate or, indeed, fictional transactions. The industry should make the provision of counterparty names a top priority and resolve confidentiality or other issues that some companies say prevent them from providing that information.

It is Staff's position that if both the index publisher and all of the energy companies providing data followed the best practices described in the CCRO paper, the resulting index would meet the standards proposed by Staff for an index that can be used for Commission-jurisdictional transactions. Staff recognizes that the CCRO cannot, nor does it attempt to, make its recommendations mandatory. Staff commends the CCRO on putting forth a serious proposal that is already part of the discussion on fixing the energy indices and will continue to be part of the solution. As discussed in the "Staff Recommendation to the Commission," many of the best practices described by the CCRO are the same as those Staff recommends be made mandatory for Commission-jurisdictional companies.

Changes by the Trade Press in the Price Index Methodologies

In the Initial Report, Staff noted that the Trade Press announced changes to its data gathering procedures in order to improve the accuracy of the reported indices. In addition, the Trade Press has continued with those efforts since the Initial Report was issued.

Platts

In the Initial Report, Staff noted that Platts had proposed refinements to its power market methodology.[35] On September 2, 2002, Platts proposed refinements to its natural gas price index methodology. Those changes included the following:

To improve the quality of information it receives for each transaction, Platts will be asking market participants to provide quantity and price, the name of the counterparty, whether the reporting company was the

[35]Initial Report at p. 37 (fn 44).

buyer or seller, and the time at which the transaction was completed. Currently, Platts obtains these data from some (but not all) market participants. Platts also is considering other refinements to increase the quality of its gas pricing data and welcomes industry input before any changes are made. Changes under consideration include the following:

- Using physical basis transactions in its monthly surveys. Basis deals transacted during the last 3 days of trading of the near-month NYMEX gas futures contract would be included with fixed-price physical deals. Among other things, Platts solicits input on whether physical basis transactions generally are compatible with fixed-price deals in some regional markets but not others.
- Requiring the signature of a senior company official to verify the accuracy of price data submitted to Platts.
- Obtaining data from back offices rather than trading desks.36

On October 28, 2002, Platts announced that it was adopting steps to strengthen the price survey of the U.S. electricity markets and that it was making similar changes to its methodology for natural gas indexes and assessments.[37]

On February 10, 2003, Platts published a statement on its views of the necessary reforms in the price index reporting process, *Market Reporting in North American Natural Gas and Electricity—Recommendations for Restoring Trust and Transparency: A Call To Action.* Platts made the following recommendations:

- Market participants should provide data from a central source in a mid- or back-office operation that would have the responsibility for confirming the accuracy and completeness of the data provided to price-reporting organizations such as Platts.
- Market participants should submit detailed transactional level data—not aggregated data.
- Market participants should provide counterparty information for each transaction reported. The naming of counterparties offers an important check for verifying the completeness and accuracy of trade data.
- Market participants should provide written certification from a senior level official, such as a chief risk officer, attesting to the accuracy and completeness of the information reported to publishers. This certification would be renewed periodically.

[36] *Gas Daily*, Proposed Refinements To US Gas Price Methodology (September 2, 2002).
[37] *Megawatt Daily*, October 28, 2002.

- Market participants should understand that these measures and others noted below can only serve to re-establish confidence and credibility in price reporting on the North American gas and electricity markets.

Platts described the high-quality data that it is seeking from market participants in order to ensure accurate price indices:

> In North America, Platts is asking electricity market participants to provide for each transaction the delivery location, trade date, start flow date, end flow date, peak or off-peak, physical or financial, price ($/MWh), volume (MW), transaction time, buy or sell indicator, and counterparty. In the gas market, Platts asks market participants to provide for each transaction the delivery location, the trade date, flow date, price ($/MMBtu), volume (Mcf), and counterparty, and to state whether the deal is fixed-price physical or basis and whether it is a buy or sell transaction.[38]

Platts further described the need for critical pieces of information such as counterparties to each trade:

> Information on counterparties, buy/sell indicators and time stamps is critical to the process of verifying data. This information will help Platts in its efforts to confirm such data characteristics as completeness (by enabling publishers to detect a provider's omission of certain deals) and accuracy, and it will serve as a check against double counting. In fact, counterparty information is one of the best means for publishers to identify inaccurate or, indeed, fictional transactions. The industry should make the provision of counterparty names a top priority and resolve confidentiality or other issues that some companies say prevent them from providing that information.
>
> Moreover, additional information such as counterparty names, buy/sell indicators and time stamps may well be useful to determine a market price and to produce better benchmarks in relatively illiquid markets or during unusual trading conditions when markets are under stress.[39]

---

[38] *Market Reporting in North American Natural Gas and Electricity—Recommendations for Restoring Trust and Transparency: A Call To Action.*
[39] Id.

Platts acknowledged that, due to the decline in energy trading and the fact that some companies have ceased reporting trade data to the Trade Press, at some trading points there is very little data from which to construct an index:

> Some US gas and electricity pricing points currently are showing little or even no trading. Platts editors can use their experience to assess the representative prices at which limited trading did occur or, in the absence of trades, would have occurred.
>
> Platts is committed to providing as much transparency as possible on how such assessments are made and what method is used to produce a given price. In US gas markets in recent months, Platts has used its traditional index methods for trading points that are sufficiently liquid and a broader assessment process when we have concluded that transactional data alone provides an insufficient base for analysis. Once the market shows signs of stabilizing, Platts will provide a clear statement on how it intends to assess US gas markets in the longer term.[40]

Platts recognizes the value of showing the degree of liquidity in the markets for which it publishes price indices and states that it is currently publishing the total trading volume for some of its indices and is moving toward publishing volumes for more of its price indices:

> Platts agrees with those who assert that the degree of liquidity of a given market should be disclosed by publishers in some fashion. It already provides information on liquidity for many of its US gas and electric benchmarks, and is moving toward expanding the provision of that type of information. While volumetric information may be subject to misinterpretation or may even encourage attempts to manipulate markets, Platts is committed to providing a window on the depth of the trading points it covers.[41]

NGI

On September 16, 2002, NGI announced that it was proposing modifications to its index price methodology for both its daily and weekly indices. The proposed modifications were designed to increase

[40] Id.
[41] Id.

the accuracy of the reported indices and more accurately reflect the way market participants are doing business. Specifically, NGI recognized the move away from negotiated fixed-price deals during bid week toward basis trading for the monthly market. NGI also stated that for several years they have been aware that some portion of the deals reported to them as fixed price have, in fact, been physical basis transactions that it has struggled to identify and remove from its calculations.

NGI proposed including the basis deals in the index and offered two suggestions for doing so: (1) the basis trades would include physical basis deals done during the last 3 days of the NYMEX trading before the near-month contract expires or (2) the basis trades would only include quotes from the last day of trading or the settlement day.

In addition, NGI asked its survey participants to report, wherever possible, counterparty information on baseload transactions and the date and/or time of the transaction (in addition to price and quantity). NGI states that the counterparty and time/date information helps them verify that reported transactions meet their survey criteria and helps to resolve questions regarding the veracity of certain data when outliers in the data are encountered. Moreover, NGI stated that a large portion of reporting companies were currently including counterparty and or date/time information.

IntercontinentalExchange

ICE is now computing indices, especially for next-day products, based on a volume-weighted average of the complete set of trades on its platform. This provides a way to avoid the sampling bias, manipulation, and verification problems associated with conventional energy indices constructed by the Trade Press and suggests that it is feasible to impose standards on indices to ensure their objectivity. In fact, ICE is encouraging the creation of swap contracts based on its next-day gas and power indices ("ICE swaps"). ICE has retained Ernst and Young, LLP to audit its procedures and verify to the marketplace the integrity of its process.

In October 2002, ICE announced the formation of the 10x Group, which publishes electricity and natural gas price indices directly from trades on the ICE platform. In addition, ICE has added a trade confirmation process, eConfirm, which has the ability to confirm trades conducted at over 100 over-the-counter brokerages and trading arenas. ICE describes the system as follows:

> The eConfirm system matches a participant's trade data to its counter party's data to execute confirmations and identify discrepancies in real time, contrasting to the manual method of confirming trades and reconciling voice broker invoices which may typically take days or weeks. eConfirm matched trades are considered to be legally binding under identical Intercontinental participant agreements that counter parties must execute in order to be active on the system.[42]

ICE states that as of February 19, 2003, there were 28 energy companies using eConfirm and those companies had used eConfirm to confirm more than 75,000 trades occurring at 49 different brokers and execution venues. Along with the trades made over the ICE platform, those trades confirmed by the eConfirm system are used in the calculation of the 10x published price indices. In addition, ICE announced an agreement with Prebon (a large energy product voice broker) in which Prebon will use the eConfirm system for all of its energy trades, and those trades will be included in the database used in calculating ICE's price indices.

In short, ICE (through its 10x subsidiary) is in the process of constructing price indices that are based solely on actual, verifiable trades from its platform or through its confirmation process. Moreover, with the agreement of a major voice broker to use ICE's confirmation system, the volume of trades reflected in its published indices is increasing. Staff is encouraged by this development and sees it as an important part of the necessary reforms to the price index reporting process.

Staff Reaction to the Proposed Changes

Staff commended the Trade Press's efforts to increase the accuracy of the indices included in the Initial Report. The further revisions to the process for reporting trade data are also positive developments. Combined with the establishment of internal controls on the part of the companies providing data to the Trade Press, the entire process has improved significantly. It is Staff's position, however, that the process is fundamentally flawed because the Trade Press data are still not subject to independent verification. In order for the published indices to be reliable, there must be a way to audit the entire information chain. The chain consists of (1) the actual trades, (2) the data provided by the companies to the reporting firms, (3) the data used by the

[42] IntercontinentalExchange press release, February 19, 2003.

reporting firms to calculate the indices, and (4) the method for calculating the indices.

As discussed in the Initial Report, the Trade Press has been willing to describe its methodology for calculating the prices despite its unwillingness to make the data available to Staff or anyone else for auditing. Combined with the industry changes in the data reporting process and the Commission's data filing requirements, three of the four components of the information chain (the actual trades, the data provided by the companies to the reporting firms, and the method for calculating the indices) could be audited. However, as long as the companies publishing the indices continue to refuse to disclose the actual calculations of the published price indices, the information chain cannot be audited and the Commission cannot verify the accuracy of the published indices. Therefore, Staff recommends that only price indices calculated from actual trades that can be verified by the Commission should be used as the basis for any Commission-approved sales of natural gas or electricity.

Future Index Reporting

As noted throughout this chapter, there have been significant improvements in the price-reporting process on both sides. Companies have moved the trade data reporting function to the risk management offices. The trading data flow directly from the companies' deal-capture system to the risk management office, and the accuracy of the data submitted to the Trade Press is verified and certified by the chief risk officer. The Trade Press is now requiring counterparty information for all data they receive to ensure the validity of the data and the accuracy of the published price indices. The Trade Press has long held the position that this is necessary, and Staff strongly agrees. Electronic platforms such as ICE have begun publishing indices based on trades coming directly from the platform.

It is important for index construction to be objective and address the fundamental problems that have been identified. The problems of sampling bias, manipulation, and verification are not inherently difficult and can be overcome with a fresh perspective and at a relatively modest cost.

A variety of trading systems exist, including electronic platforms, voice brokers, hybrid markets, and trading floors. However, in all of these designs it is feasible to compute the average price over a specified period of time. There is no reason for prices to reflect the impression of individual traders. Instead, they should reflect the reality

of the actual trades. The approach taken by ICE to compute its indices by providing the volume-weighted average execution price for the specified period applies not only to ICE and other electronic platforms, but also to individual voice brokers, hybrid markets (a combination of a voice broker and an electronic platform), and even trading floors. This raises the question of how to enforce these standards.

Any marketer or broker could be required by "anti-fraud" regulations or legislation to provide accurate index information (such as average prices and volume). This should be a basic requirement for a market center such as a trading platform, broker, or trading floor. Although not all market contexts have such reporting requirements (e.g., foreign exchange trading does not have these restrictions), they are important for domestic energy markets in light of the extent of reliance on index prices for pricing physical flows and the small number of market participants for many products (which leads to the potential for market manipulation). Similarly, our discussion of (ex post) transparency in Chapter IX emphasized the value of requiring timely trade reports; this could be enforced by requiring that these reports be subject to appropriate anti-fraud standards. The data and informational requirements for trade reporting are much stronger than those for index reporting, which is actually an aggregate form of trade reporting.

Services that purport to measure index prices across platforms or voice brokers should be governed by the same anti-fraud rules. Acceptable indices in this context should also provide appropriate volume-weighted averages to aggregate across portions of the marketplace. The computation of such measures would require average prices and volumes from those markets and/or brokers, whose prices are included in the benchmark.

This raises the question about whether reasonable indices could be computed solely from a single online platform or two (such as ICE and TradeSpark) with an automated computational process. Because such an index would only reflect online transactions, it would not reflect all of the buying and selling of a particular product. Staff recognizes that in a perfectly functioning market, arbitrage would drive the prices between on- and off-line exchanges together. However, Staff has learned from this investigation that energy markets are not always perfectly functioning. As such, the ideal index should capture as much of the entire universe of trades as possible. Along that line, as discussed earlier in this chapter, at least one online exchange has entered into an agreement with a major voice broker that would include the broker's transactions in its price index.

Staff Recommendations to the Commission

Staff makes the following recommendations for the Commission to consider regarding the characteristics of any future published price indices and Commission action to ensure the accuracy and integrity of price indices:

1. Any company publishing price indices to be used as a basis for Commission-jurisdictional transactions, e.g., natural gas pipeline balancing or market-based electricity pricing, should be subject to audit by the Commission to ensure the accuracy of the data going in and the calculations themselves. That is, an index that meets the requirements established by the Commission for use in Commission-jurisdictional transactions would have the Commission's seal of approval. All data used in the index calculation, including data that are thrown out (e.g., outliers, questionable reported trades, trades reported without counterparty verification), should be available to the Commission. In the Initial Report, Staff described the verification, auditing, and oversight procedures associated with NYMEX energy trading. Staff suggests that these procedures should serve as a model for price index reporting in the future. The characteristics of NYMEX and its price index calculations are as follows:

- NYMEX is an organized exchange subject to CFTC regulation.
- NYMEX is required by the CFTC to maintain and enforce an internal auditing mechanism and to maintain records of trading activity so a clear audit trail is possible.
- NYMEX is required to conduct, with CFTC oversight, market surveillance and trade surveillance designed to prevent market manipulation and other anti-competitive activity.
- The Futures Trading Practices Act requires that trade information be submitted to NYMEX and time-stamped within 1 minute of a trade. NYMEX requires its traders to use a special trading pad that provides NYMEX with an unalterable audit trail through the use of individually numbered, time-stamped computer scans of trader records.

2. The Commission should condition all market-based rate and blanket natural gas sales certificate authority on companies providing complete, accurate, and honest information to any entity that publishes price indices. The information must be detailed transactional data that includes:

- Price.
- Volume.
- Delivery point.
- Duration (i.e., hourly, daily, monthly).
- Date and time (to the minute) of the transaction.
- Whether the transaction is a purchase or a sale.
- Counterparty.

It must be clear that manipulating index prices is a violation of the tariff and grounds for revoking market-based pricing or blanket natural gas sales authority and for requiring disgorgement of any profits resulting from the manipulation.

3. The Commission should require that jurisdictional entities retain all information concerning their transactions and any and all information submitted to any entity publishing natural gas or electricity price indices and provide it to the Commission upon demand. Such information would promote more transparent markets and reduce incentives to manipulate or attempt to manipulate energy markets. For example, the CFTC requires that "[a]ll books and records required to be kept by the Act or by these regulations shall be kept for a period of 5 years from the date thereof and shall be readily accessible during the first 2 years of the 5-year period. All such books and records shall be open to inspection by any representative of the [CFTC] or the United States Department of Justice."[43]

4. The Commission should approve standard product definitions for published natural gas and electricity price indices used in jurisdictional transactions and standard methodologies for calculating the price indices.

Staff has a specific recommendation for an alternative to the published price indices that meets the criteria specified above. That is, the Commission should require any jurisdictional transaction that is based on a published price index to be taken from an index that is calculated directly from the trade data from one or more many-to-many electronic exchanges and voice brokers that meet all of the criteria specified above. The exchange or voice broker must be audited by an outside entity, and the audit must be subject to Commission review. An index calculated as such would be free from the ability and incentive of

[43]Commodity Futures Trading Commission Commodities Exchange Act Regulation 1.31.

traders to manipulate the prices and would be feasible in terms of implementation cost, time, and verification.

Staff further recommends that the process for establishing standards for price reporting be established by the Commission, with input and cooperation from the energy industry and the price reporting firms. In addition, other government agencies, such as the CFTC and the Energy Information Administration, should be involved in the process. The process should begin with a technical conference at FERC.[44]

As described throughout this chapter, there are a significant number of companies whose employees manipulated or attempted to manipulate the published price indices by reporting inaccurate or misleading data to the Trade Press. Those manipulations and attempts to manipulate the published price indices may involve criminal violations. In fact, as of February 28, 2003, United States Attorneys have filed criminal charges against two former traders (one from Dynegy and one from El Paso Merchant Energy). Staff has provided the United States Attorneys' Offices any relevant information regarding these cases and will continue to do so. In addition, Staff has provided other government agencies (including the CFTC and the SEC) with any relevant information regarding their investigations of index price reporting and will continue to do so.

Also, as described in this chapter, many of those companies have taken internal measures to correct the problem, such as firing or disciplining employees who manipulated or attempted to manipulate the indices; moving the reporting process away from the trading desk and toward the risk management office; and having a company officer attest to the accuracy of data reported to a trade publication.

Staff recognizes the importance of accurate price indices to the overall health of competitive energy markets. The companies discussed at length in this chapter are significant participants in U.S. electricity and natural gas markets. In order for the published price indices to be accurate and credible, they must receive complete and accurate information from these companies. As such, Staff recommends that the following companies be required to show the Commission that they have fixed their internal processes for reporting trading data to the Trade Press:

- Dynegy
- Aquila
- AEP

[44]Commission Staff has scheduled a technical conference relating to the issue for April 24, 2003.

- El Paso Merchant Energy
- Williams
- Reliant
- Duke
- CMS
- Mirant
- Coral
- Sempra Energy Trading

At a minimum, these companies need to show the following:

- Those employees, including trading desk heads and managers, who participated in manipulations or attempted manipulations of the published price indices have been disciplined.
- The company has a clear code of conduct in place for reporting price information.
- All trade data reporting is done by an entity within the company that does not have a financial interest in the published index (preferably the chief risk officer).
- The company is fully cooperating with any government agency investigating its past price reporting.

Conclusion

The process for reporting natural gas price indices was fundamentally flawed and must be fixed. Traders had the ability and incentive to manipulate the published indices and they did so. Given the degree of systematic manipulation described in this chapter, the published indices could not possibly be accurate based solely on the publishers' editorial judgement, the traders' feel for the market, or the hope that competing traders could offset each other's false reporting.

Staff began the investigation looking for evidence of energy price manipulation in the West. Staff found evidence of manipulation (direct and indirect) of the published natural gas price indices at significant trading points all over the United States—the U.S.-Canada border in Washington (El Paso), Oregon and San Francisco (Dynegy), the Gulf Coast (AEP), the Great Lakes (CMS), the Northeast (Williams), the Henry Hub in Louisiana (Enron), and the Southern California-Arizona Border (Enron and Reliant).

In many cases, electricity prices are directly (through explicit contracts) or indirectly (through the generation costs of electricity suppliers) determined by natural gas prices. Therefore, the manipulation of natural gas prices also affected electricity prices. As the agency of the U.S. Government with the statutory obligation to ensure just and reasonable electricity rates, the Commission cannot rely on a recipe of offsetting false reports, traders' feel for the market, and editorial judgement for accurate price indices.

As noted in this chapter, there has been a movement within the industry to fundamentally reform the price reporting process. Suggestions for reform and tangible reforms have come from market participants, risk officers, the trade publications themselves, new entrants into the price reporting business, government agencies, consumer groups, and others. Moreover, Commission Staff will convene a technical conference on April 24, 2003 on the issue of price reporting, bringing together these parties and working toward a solution. It is clear that the parties involved recognize the problem, agree that a competitive energy market must have accurate price indices to function properly, and are willing to make changes to the process in order to ensure that the indices are accurate and reliable.

IV. Staff Alternative Mitigation Proposal

Summary and Conclusions

In this and previous chapters of this Report, Staff concludes that California spot gas prices were artificially high due to market dysfunctions, illiquidity, misreporting, and a rupture causing an abnormal pipeline capacity shortage. The spot gas prices reflected extraordinary basis differentials that far exceeded the cost of transportation and reached levels that would never have been sustained in a competitive market. The effects of these inflated gas prices were greatly magnified because they were used in the California Refund Proceeding to compute clearing prices for the entire electric spot power market. While there is no way to precisely replicate the level that spot gas prices would have reached in a competitive market, Staff recommends the use of producing-area prices plus transportation as a proxy for competitively derived gas prices in computing the market-clearing prices in the California Refund Proceeding. Over the 9-month refund period, Staff's proposal would reduce gas costs used in the refund formula by $7.03 in southern California and $4.18 in northern California, or about $5.60 on average.

That said, many generators paid these distorted gas prices and fundamental fairness dictates that they be able to recover their costs. Accordingly, Staff also recommends that generators be made whole for the gas prices they paid, but that this recovery be on a dollar-for-dollar basis and not be part of the market-clearing price.

Introduction

In its July 25, 2001 Order, the Commission established the scope and methodology for calculating refunds for bulk power sales in the California spot power markets made between October 2, 2000 and June 20, 2001. The prescribed methodology would determine the mitigated market-clearing price (MMCP) based on the heat rate of the least efficient generator dispatched in the ISO's real-time energy market multiplied by the spot price of gas. The purpose of this methodology was to "provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs."[1]

In its August 13, 2002 Initial Report on this investigation, Staff concluded that the California spot price gas indices may have been

[1] 95 FERC ¶ 61,418, mimeo, p. 38.

manipulated and were not appropriate for price mitigation. Staff recommended that mitigated market-clearing prices be based on producing-area spot index prices plus a transportation allowance. To the extent that generators paid higher prices for gas to nonaffiliated suppliers, these costs would be recoverable though a fuel uplift offset to refund obligations. Comments filed in response to the Initial Report assert that despite Staff's concerns regarding index manipulation, generators did in fact pay the California spot price for gas, and the spot gas price was driven by fundamental supply and demand forces.

In concluding this investigation, Staff has determined that the California spot gas prices were affected by the same factors that rendered the electric power market dysfunctional, were closely linked to the price levels prevailing for electric power, and reached extraordinary levels in part due to pipeline capacity shortages, speculative trading, and attempted market manipulation, including index price misreporting. Staff concludes that the Commission's objective of creating mitigated prices that would emulate the result of a competitive market cannot be achieved by using California gas spot prices.

Staff reaffirms its recommendation that the Commission modify the market-clearing price formula in the California Refund Proceeding to use producing-area prices plus a tariff rate transportation allowance instead of California spot gas prices. Staff believes that the California spot gas prices would have closely tracked producing-area prices plus transportation had the gas market been free from the distorting influence of electric market dysfunction and attempted price manipulation and only influenced by the interaction of high demand and limited supply. Some portion of the premium over producing-area prices also reflected, to some degree, pipeline capacity shortages including the El Paso Carlsbad rupture. Ideally, the portion of the increased border prices attributable to legitimate scarcity should be reflected in the market-clearing price. However, Staff does not believe the effects of scarcity can be separated from those of market dysfunction and price manipulation. Therefore, Staff recommends that fuel input costs above the producing-area cost allowance should be recoverable as a refund offset depending on each generator's heat rate, but would not become an input to the market-clearing price.

In the Initial Report, Staff acknowledged that its proposed method for calculating the MMCP and refunds for California was a regulatory response to a breakdown of the California electricity market:

> Staff's proposed substitute is a regulatory solution to a market failure. Staff recognizes that the basis differential between

> trading points (in this case, between the western production basins and the California delivery points) represents differences in fundamental supply and demand conditions between points, particularly the scarcity of natural gas due to limited gas transportation to California, and is an important signal for both buyers and sellers. Under normal circumstances, that basis differential should be preserved so the MMCP is the true marginal cost of the last plant producing electricity in California. However, during the period in question, circumstances were not normal. California's electricity market was in crisis, and the combination of the inelastic demand for electricity and the fact that natural gas was the fuel used by the marginal electricity generators was transmitting the problems in the electricity market back to the gas market. That is, electricity generators in California would be willing to pay almost any price for natural gas because they would be able to pass any gas costs through the wholesale electricity market. Given these conditions and the problems with the published California natural gas price indices described above, Staff finds that the proposed substitute, along with the opportunity to recover verifiable gas costs that reflect the scarcity premium, as specified above, is the best way for the Commission to establish just and reasonable rates for the refund period.

The facts uncovered in the investigation since the August 2002 Initial Report confirm Staff's position that the California electricity market was fundamentally flawed and that the dysfunction in the electricity market fed back into the natural gas market. In fact, due to the influence of EnronOnline (EOL) and the other problems described in this Report, the natural gas market at the California border was itself one of the forces driving the meltdown of the California electricity market.

The proposed solution in this chapter refines Staff's August 2002 proposal by allowing generators to recover costs and earn a fair return on their investment while protecting California consumers from unjust and unreasonable electricity prices. It allows the companies that made investments in efficient generators to keep the profits derived from generating electricity at a lower cost than less efficient generators (by setting the MMCP as the marginal heat rate times the basin-plus-transportation natural gas price) without giving them an "efficiency bonus" by leveraging the portion of the natural gas price that is largely attributed to the market dysfunctions described throughout the Report,

which would come at the expense of the California utilities and ultimately of California consumers.

The proposed methodology does, however, recognize the need for generators to recover the cost of producing electricity in California during the refund period. Many generators actually paid index prices and will receive a one-for-one payment to recoup their costs. As described in this chapter, the California index price reflects the scarcity of the natural gas delivered to the California border along with the dysfunctions and manipulations of the market. Ideally, Staff would separate the scarcity from the manipulation and dysfunction and calculate a price that reflected only the true scarcity. In Staff's view that process, if possible, would take years. Staff cannot recommend that this uncertainty and imprecision be introduced into a clearing price and used to value all the power in an entire market. Staff's proposal strikes a balance by using the basin-plus-transportation price, which reflects no scarcity for the clearing price, and using the California index price, which reflects scarcity as well as market dysfunction and manipulation for the cost recovery. It protects California consumers from the multiplier effect of running the California index price through the MMCP without unduly penalizing generators who paid inflated prices for gas in the spot market.

Throughout this Report, Staff has proposed penalties to those who did manipulate the natural gas market and remedies so that it does not happen again. Generators who purchased gas at artificially high prices due to market dysfunction and manipulation do not deserve to be penalized any more than the California electricity consumers who clearly paid excessive electricity prices due to the gas and electricity market manipulation and dysfunction.

Why California Gas Spot Prices Should Not Be Used for Price Mitigation

In specifying that California spot gas prices be used to emulate the outcome of a competitive market, the Commission assumed that the gas spot market was truly competitive and could provide a reliable foundation for emulating the outcome of a competitive power market. Staff believes, based on information developed in this investigation, that the prices established in the gas spot market were not the outcome of fundamental supply and demand forces, but were affected by dysfunctional spot electricity markets, an illiquid spot gas market, speculative trading, and, in some instances, market manipulation. All

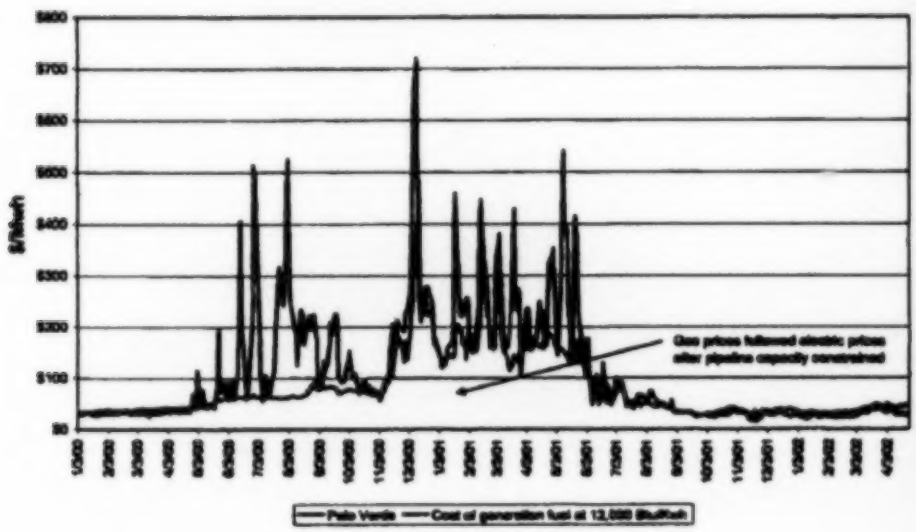
of these factors influenced the California spot prices. While the analysis in Chapter II of this Report attempts to quantify the impact of speculative trading and churning on EOL, simply removing that portion from the California spot price would not remove all vestiges of market dysfunction from the gas prices used for power market price mitigation.

Gas Prices Were Driven by Power Prices Once Pipeline Capacity Became Constrained

As Figure IV-1 indicates, the relationship between gas and electric power prices changed over time. In the summer and fall of 2000, electric power prices rose to very high levels while gas prices stayed relatively low. Once colder weather arrived in November and December 2000, and the combined heating and power load fully used available pipeline capacity, gas prices started to generally follow electric prices.

Figure IV-1

Palo Verde Power Price vs. California Gas Price
High Power Prices Preceded Gas Price Rise



This trend illustrates a fundamental dynamic in natural gas pricing: in a nonconstrained market, gas prices are driven by seller competition and the seller's marginal cost; in a constrained market, prices are driven by buyer competition for scarce resources, and prices reach the buyer's value for gas—in this case, the value of gas for power generation. In other words, in the capacity-constrained California market, gas prices were driven in substantial part by power prices. In this regard, Staff agrees with the observation of Henning and Sloan of EEA in comments filed by Duke Energy:[2]

> Indeed, in California, when power prices exploded to record heights, power generation customers were willing to pay astronomically high gas prices since electricity prices made it economically feasible to do so.

Pipeline Capacity Constraints Were Not Entirely Market Related

During the refund period, the El Paso pipeline was operating at reduced capacity due to the Carlsbad pipeline explosion. This reduced El Paso's capacity to California by 270 MMcf/d, more than 10 percent of its average actual deliveries. The loss of this capacity was clearly not anticipated, but it had a large impact on price. Had that capacity been available, the spot market price would in all likelihood have been substantially lower than the price that was paid. When warmer weather returned during the first 10 days of January 2001, market demand dropped by 240 MMcf/d compared with the last 10 days of December 2000. The corresponding price differential between California and Southwest price points dropped from $7.25 to $2.20/MMBtu.[3] While this remains some four times higher than transportation costs to the border, the difference strongly implies that the Carlsbad rupture contributed significantly to the extraordinarily high California spot gas prices. Although a pipeline outage has an element of legitimate scarcity, there is no way to isolate these scarcity costs. In addition, Staff does not believe that there is any compelling reason to include

[2]Comments of Duke Energy filed October 15, 2002 in Docket No. EL00-95-045, Exhibit B, p. 11.

[3]For the period from December 21-31, 2000, average El Paso deliveries to California were 2,788,244 Mcf/d, the average California spot price was $16.73, and the average Southwest spot price was $9.48. For the period from January 1-11, 2002, average El Paso deliveries to California were 2,547,007 Mcf/d, California spot prices averaged $11.40, and Southwest prices averaged $9.20.

costs related to such an abnormal event in the clearing prices for an entire electric spot market.

California Gas Prices Were Artificially High

As discussed elsewhere in this Report, the investigation has identified evidence of gas market dysfunction, speculative trading, and index misreporting. These factors, in addition to the linkage between gas and electric markets, resulted in artificially high gas prices. Staff recommends that the Commission reconsider whether high gas prices should automatically mean that generators are entitled to higher operating profit, especially if gas prices are found to be artificial.

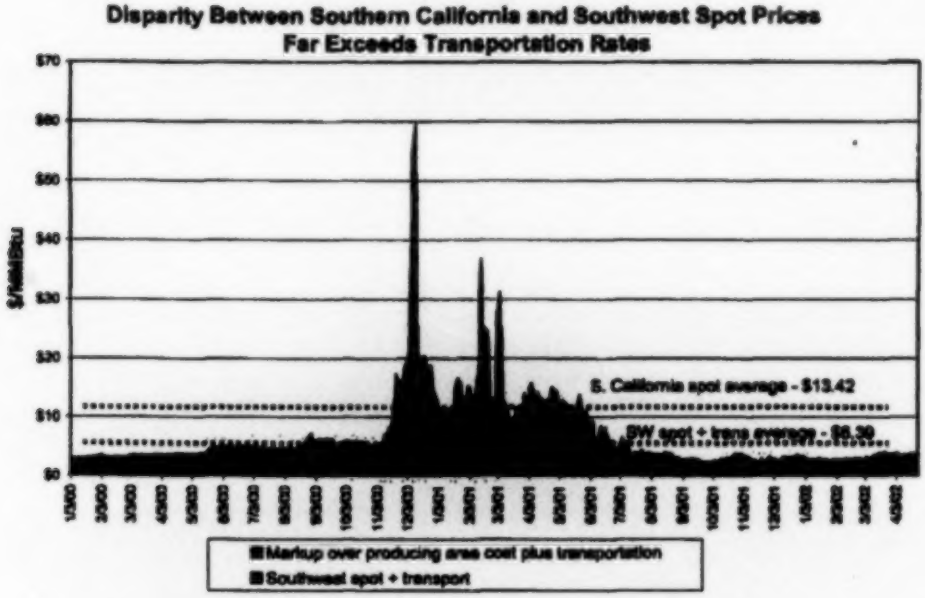
Spot Gas Prices Contained a Transportation Premium Far in Excess of Pipeline Transportation Rates

During the refund period, California spot gas prices reached heights never before seen in the California market, rising to $59.42/MMBtu on December 11, 2000. On average, southern California spot prices were $13.42/MMBtu compared with $5.53 for the Southwest spot supply for the refund period.[4] The markup over Southwest spot prices averaged $7.89 compared with a maximum transportation rate of $0.86, including fuel. The markup in excess of transportation costs, averaging $7.03, represented 52.4 percent of the reported spot price.[5] Figure IV-2 shows the disparity between Southwest spot gas costs and southern California spot prices.

[4]Southern California spot prices were based on *Gas Daily* price for SoCal large packages. Southwest price was based on the average between *Gas Daily* Waha and El Paso – Bondad pricing points. All *Gas Daily* prices were the midpoint of the common range.

[5]Transport cost: El Paso IT—$0.3968, 3.74 percent fuel at $5.53 average price; SoCal GT F5—$0.2542 including fuel.

Figure IV-2



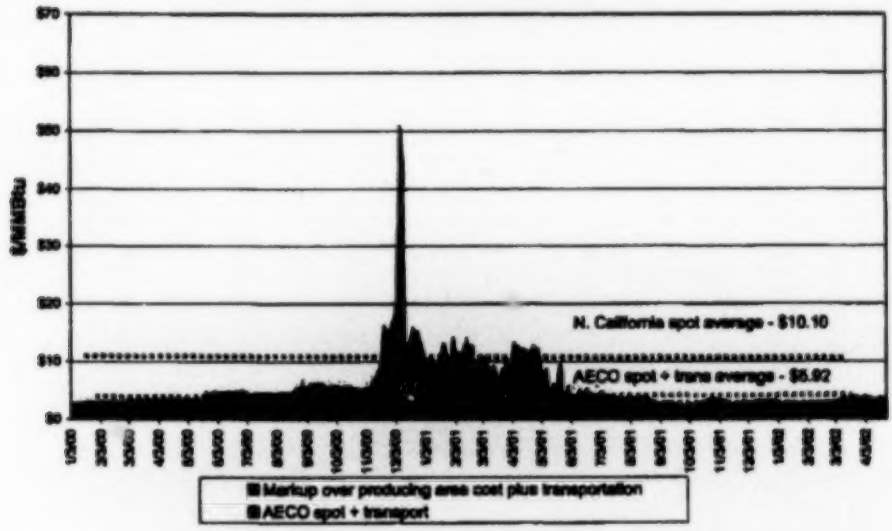
During the refund period, the Southwest gas price also reached record heights, reflecting commodity value in the producing area. The average Southwest price of $5.53 during the refund period was 40 percent higher than prices in the preceding summer, and more than twice the price during the preceding and succeeding winter periods.

Similar prices existed in northern California. Figure IV-3 shows the disparity between the PG&E citygate price and upstream Canadian supplies during the refund period. The peak PG&E citygate price reached $50.79/MMBtu on December 8, 2000, averaging $10.10/MMBtu, compared with $4.79/MMBtu for the AECO Canadian producing-area point over the refund period.[6]

[6]Northern California spot prices were based on the *Gas Daily* PG&E citygate pricing point; AECO prices from *Gas Daily*. All *Gas Daily* prices were the midpoint of the common range.

Figure IV-3

Disparity Between Northern California and Canadian Spot Prices Far Exceeds Transportation Rates



The markup over Canadian spot prices averaged $5.31 compared with a maximum transportation rate of $1.13, including fuel. The markup in excess of transportation costs, averaging $4.18, represented 41.4 percent of the reported spot price.[7]

Under the Market-Clearing Price Mechanism, Generator Operating Profit Increases With the Gas Price

Artificially High Gas Prices Equal Artificially High Profits

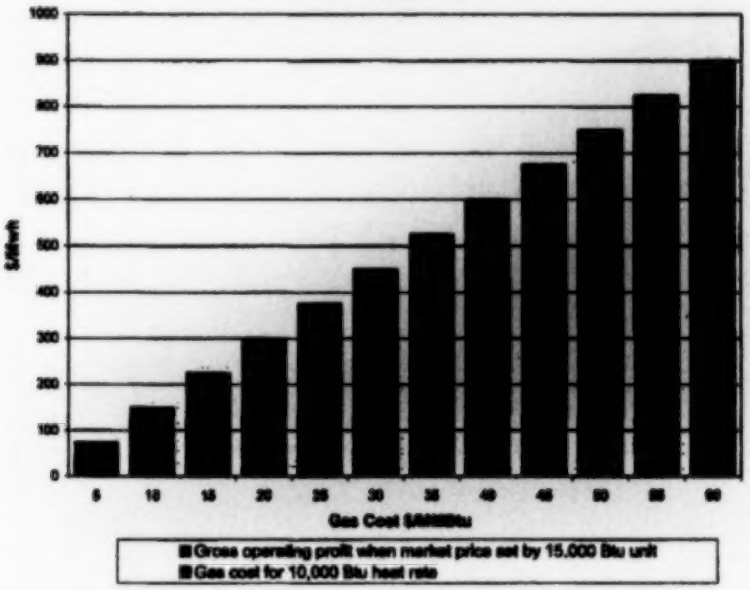
Under the July 25 Order's mitigation methodology, the gas component of the market-clearing price is determined by multiplying the spot gas price by the heat rate of the least efficient generator dispatched by the ISO. All other generators receive this same price. Generators with heat rates more efficient than the market-clearing unit retain the difference between the market-clearing price and their actual fuel costs, referred to here as gross operating profit. The gross operating profit is a function of the gas input price, as shown in Figure IV-4. For example, if the least efficient marginal unit has a heat rate of 15,000 Btu/kWh

[7]Transport cost: TransCanada—$0.1820 including fuel; PGT IT—$0.2722, 3.06 percent fuel; PG&E G-AFT—$0.2687; PG&E G-EG—$0.1995, 1.37 percent fuel at $4.18 average price.

and the spot gas cost is $5/MMBtu, the gas cost component of the mitigated market-clearing price would be $75/MWh. A 10,000 Btu/kWh unit would incur only $50/MWh in gas costs due to higher efficiency, yielding a $25/MWh gross operating profit. At a $20/MMBtu gas price, however, the gross operating profit of the 10,000 Btu unit rises to $100/MWh. At $60/MMBtu, the gross profit rises to $300/MWh.

Figure IV-4

Generator Profitability Rises With Gas Cost



Thus, under the July 25 Order, the profitability for generators more efficient than the market-clearing unit is directly related to gas input prices. The higher the gas price, the higher the average generator's allowed gross operating profit. The single clearing price auction, where all sellers receive the price at which the last unit of supply clears the market, was an integral part of the California restructuring framework. The choice of a single clearing price, as opposed to a market design where each seller receives the particular price it demands, was the result of an extensive stakeholder process with the support of many economists.

Modification of the Mitigated Market-Clearing Price Methodology is Needed

As shown above, the July 25 methodology rewards generators who paid high gas prices with mitigated power prices that, for most generators, produce higher gross operating profit than under normal market conditions. Staff believes that California spot gas prices reached levels that would not have existed in a competitive gas market. The shortage conditions that existed were not wholly market related, but rather were in part the result of an abnormality—the El Paso Carlsbad rupture. Further, various attempts to manipulate prices, as described within this Report, cast doubt on whether the California spot prices were legitimate.

Staff believes that the problems identified with California spot gas prices warrant a revision in the Commission's price mitigation methodology. The challenge is to design price mitigation that compensates the marginal generator for gas costs incurred in good faith to provide needed power supply, while recognizing that unusually high gas costs overcompensate other, more efficient generators. While efficiency should be rewarded, Staff believes this reward should have limits, particularly at the extraordinary and questionable gas price levels that prevailed during the refund period.

Options for Establishing Natural Gas Prices for Power Price Mitigation

In Staff's view there are various approaches the Commission should consider to determine the appropriate natural gas price level for establishing mitigated power prices. As discussed above, Staff does not support using the California spot index price.

The central problem is to determine what level California spot market-clearing power prices would have reached in a hypothetically competitive market, free of the distorting influences of power market dysfunction, gas market manipulation, and lack of liquidity. Staff submits that there is no clean way of separating the components of the artificially high California spot gas prices to determine such a hypothetical price level. In Staff's view, the best way to ensure that the mitigated market-clearing price is completely independent of

distortion and manipulation is to substitute producing-area prices plus a tariff transportation allowance for California spot prices. This approach would approximate gas market conditions had there been no electric market dysfunction, no pipeline constraints, and no gas price manipulation. As explained in the Initial Report, Staff believes the index price for Southwest and Canadian producing areas is reliable and was not subject to manipulation because these prices correlate well with the larger and more liquid Henry Hub market. [8]

Unfortunately, many generators did in fact pay prices that included the effect of these factors. Fairness dictates that generators be permitted to recover these costs. However, since these costs reflect (at least in part) some degree of artificiality, they need not be reflected in the mitigated market-clearing price for power. Treating these costs on a dollar-for-dollar basis allows the recovery of legitimate scarcity costs and is consistent with the approach the Commission adopted in the July 25 Order for nitrogen oxide credits.

The remaining issue is the level of costs above the producing-area allowance that should be recoverable. Staff proposes that the Commission consider three options for determining the level of the additional fuel cost pass-through allowance.

The first option would be to adopt the approach recommended in the Staff's August 13 Initial Report. At that time Staff proposed to limit the level of additional fuel cost recovery to the average price of each generator's portfolio of gas supplies from nonaffiliated suppliers. In response to that proposal, several commenters pointed out that the portfolio approach would penalize generators who managed to keep their gas costs below the California spot index price. Determining actual costs could involve substantial effort and subjective cost allocations. Further, comments indicated that in most cases generators did in fact pay the California spot gas index price. [9]

The second option would be to determine the additional fuel cost allowance based on the California spot gas index rather than on the gas portfolio cost. Under this method the cost of fuel over and above the production area allowance would be determined by each generator's heat rate multiplied by the amount the California spot index exceeded the producing-area index plus fuel and transportation. This approach would simplify the additional fuel cost determination and avoid an indepth analysis of gas portfolios and costs. Since many generators paid the index price for their spot gas, a detailed analysis of their

[8] Initial Report at p. 71.

[9] See study by Drs. Wang and Reishus filed by the comment of the Generator Group (Mirant, Dynegy, Williams, Duke Energy, and Reliant Energy).

actual portfolios should not produce substantially different results. Further, the gas portfolio approach could deprive generators of the benefits of responsible fuel cost management. Those generators who took the risk of acquiring firm service and supported pipeline capacity expansions, for example, would be entitled to keep the difference between their fuel costs and the California border price. The market-clearing price for electricity, however, would be based on the production area price allowance.

A third option would base the additional fuel cost allowance on the price of actual California daily spot market gas purchases rather than rely on the reported indices. This option would still rely on daily spot market prices to determine the additional fuel cost allowance, but would establish those prices based on a review of actual spot market purchases by generators serving the California market. This approach would test the claim by the generators that the reported California spot market index corresponded closely with actual spot market gas costs. This approach would require generators to file actual spot market purchase costs, which would be more data intensive than relying on the reported gas indices, but would reduce uncertainties as to whether the reported index was in fact what generators paid for spot market gas.

How the Alternate Market-Clearing Price Mechanism Would Work

The Staff's proposal for mitigated power price has two components—an alternate market-clearing price and an additional fuel cost allowance. The alternate market-clearing price would be based on the fuel cost of the least efficient unit dispatched priced at the producing-area price index plus transportation and fuel. The additional fuel cost allowance would be passed through on a dollar-for-dollar basis as an offset against refund exposure.

Figure IV-5 illustrates the separate determination of the market-clearing price and the additional fuel cost allowance at various generator heat rates. The figure assumes for illustration that the market-clearing unit had a heat rate of 15,000 Btu/kWh and the average heat rate for California generators is 10,000 Btu/kWh.[10] During the refund period, the average southern California gas spot index price was $13.42/MMBtu, and the average Southwest spot price

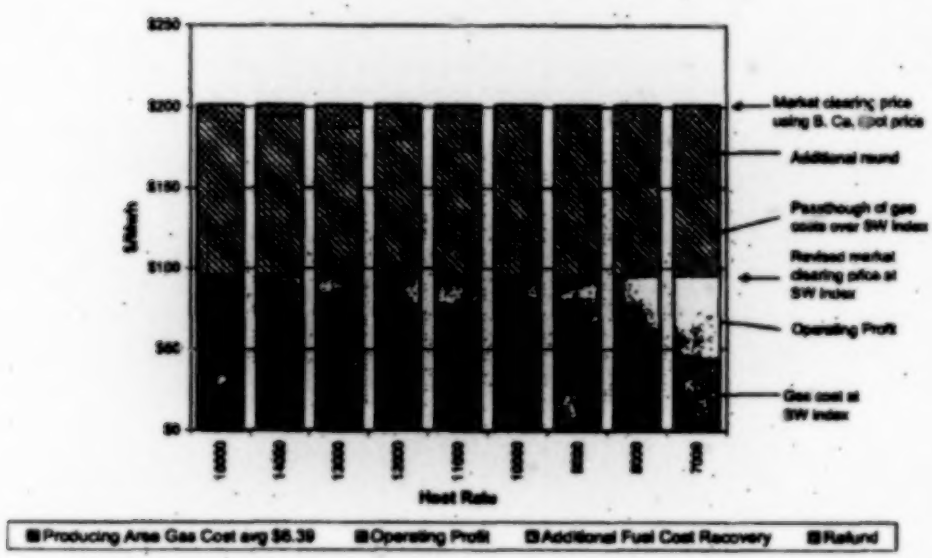
[10]The average heat rate at full capacity for generators reported by the California ISO in Docket No. EL00-95 was 10,189 Btu/kWh (derived from Exhibit ISO-8).

plus transportation was $6.39/MMBtu. Operation and maintenance costs were excluded for the sake of simplicity.

As illustrated in the figure, the alternate market-clearing price for a marginal unit (15,000 Btu heat rate) would be $95.84/MWh and the additional fuel cost allowance would be $105.48/MWh,[11] for a total of $201.32/MWh. While this is the same total price as that produced using the California spot price, the market-clearing price would be reduced to $95.84/MWh. For a 10,000 Btu heat rate unit, however, the additional fuel cost allowance would be $70.32/MWh[12] (because the more efficient unit uses less fuel), for a total of $166.16/MWh, or $35.16/MWh less than the July 25 Order methodology. Again, the $70.32/MWh would not be part of the market-clearing price.

Figure IV-5

Using Producing Area Prices for the Market Clearing Price Provides Reasonable Operating Profit



Under the alternate market-clearing methodology, units more efficient than the marginal unit would receive an efficiency profit, but that profit would be based on the producing-area index price. The additional fuel allowance would be based on each individual generator's heat rate and would be passed through as a refund offset, but would not be included in the market-clearing price.

[11] Alternate market-clearing price: $95.84/MWh = 15,000 Btu/kWh × $6.39/MMBtu. Additional fuel cost allowance for a 15,000 Btu heat rate: $105.48/MWh = 15,000 Btu/kWh × ($13.42 - $6.39)/MMBtu.

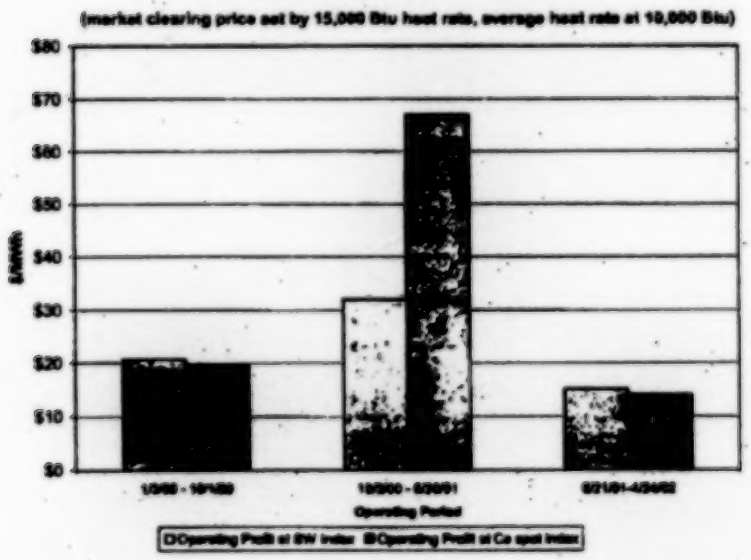
[12] Additional fuel cost allowance for a 10,000 Btu heat rate: $70.32/MWh = 10,000 Btu/kWh × ($13.42 - $6.39)/MMBtu.

Impact of the Proposed Alternate Mitigation Methodology

Figure IV-6 compares, for various periods, the estimated generator gross operating profit under the July 25 Order and Staff's proposed alternate mitigation methodology. During the refund period, an average generator with a 10,000 Btu heat rate would have earned an average gross operating profit of $67/MWh based on California spot prices, and $32/MWh under the alternate methodology.

Figure IV-6

Operating Profit Comparison
Southern California vs. Southwest Index



Comparing the calculated $32/MWh operating profit for the refund period with levels in periods before and after shows that the alternate methodology satisfies the Commission's goal of providing generators with a reasonable opportunity to recover their fixed costs. During the refund period, the average computed operating profit was $32/MWh, or 55 percent higher than that of the preceding 10-month period and twice the operating profit level experienced in the succeeding 10-month period.

The $32/MWh operating profit substantially exceeded the capital recovery requirement of a hypothetical new power project. The California Energy Commission (CEC) estimates that a new combined cycle gas turbine would require capital recovery of between $85 and

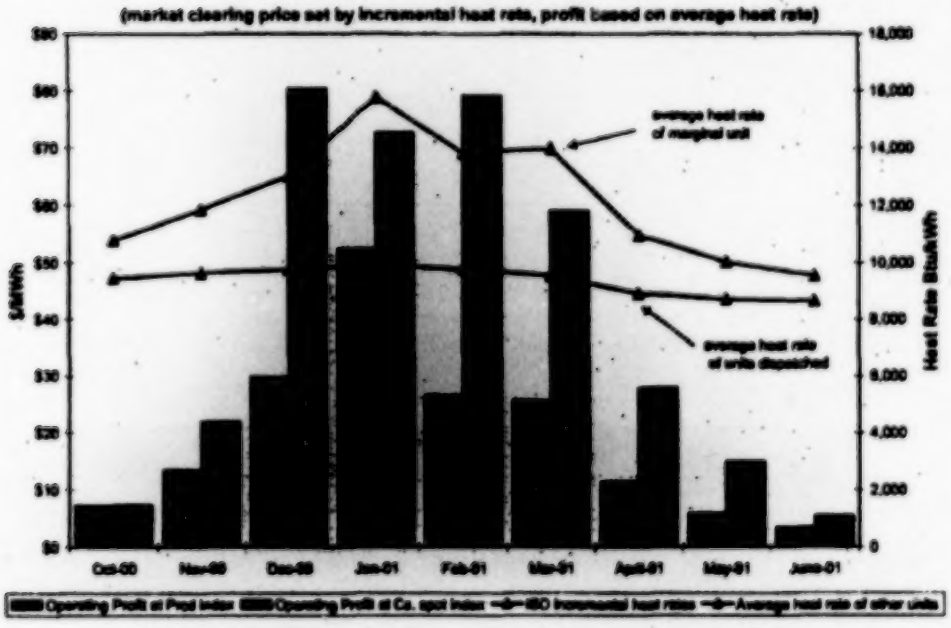
$100/kW per year, or $16.17 to $19.03/MWh at a 60-percent plant factor.[13] As such, gross operating profits were in line with capital costs before and after the refund period. This indicates that the single clearing price auction produced reasonable results except when the gas input prices were artificially inflated.

Use of Incremental Versus Average Heat Rates

On December 12, 2002, Administrative Law Judge (ALJ) Birchman issued his Certification of Proposed Findings on California Refund Liability. The ALJ found that marginal heat rates for refund determination purposes should be based on the change in heat rate over a given load interval rather than the average heat rate for generating power at a given load level. The incremental heat rates used by the ALJ averaged 12,268 Btu/kWh on a load-averaged basis for the refund period, versus the 15,000 Btu/kWh used for illustrative purposes in the preceding examples.[14] Figure IV-7 shows how generator operating profit would be affected by the Staff refund methodology if the Commission adopted the ALJ's heat rate finding.

Figure IV-7

Monthly Operating Profit Using Incremental Heat Rates



[13]California Energy Commission, *2002–2012 Electricity Outlook Report*, pp. 32-33.
[14]Heat rates from Exhibit ISO-3, in Docket No. EL00-95-045. Load averaging based on daily system load as reported on the California ISO Oasis Web site.

The figure shows that the combination of the incremental heat rates used by the ALJ and the Staff's recommended producing-area index for price mitigation would reduce operating profit levels considerably. Using the ALJ heat rates and the California spot gas price, the average operating profit would be $41.80/MWh for the average generator operating at a 9,400 Btu heat rate. Using Staff's recommended producing-area gas price methodology and the ALJ's heat rates would reduce average operating profit to $20.04/MWh. This level of operating profit is within the range needed to support new generation investment.

Response to Comments on Initial Report

Did the index reflect what generators actually paid for gas?

Drs. Wang and Reishus looked at natural gas transaction data for Mirant, Dynegy, Williams, Duke Energy, and Reliant Energy (Generator Group) for the refund period. They found that the price the Generator Group actually paid for gas was nearly perfectly correlated with the index price. They conclude that the index price was an accurate measure of the market price, contrary to Staff's conclusions.

Dr. Van Vactor testified on behalf of Coral Energy. He analyzed the reported price data from all of the major natural gas price reporting publications and compared the reported natural gas prices with the prices posted on another trading platform, IntercontinentalExchange (ICE), for the period beginning April 2001. He found that the prices were nearly identical during the refund period and concluded that the price data from McGraw Hill (Platts), Intelligence Press, and the Energy Intelligence Group were accurate. He also cited the similarity of the reported prices to those reported on ICE after April 2001 and argued that this similarity provides further evidence that the reported prices were accurate.

Staff response:

Staff believes that the price generators paid correlates closely with the index because the purchase agreements were for index-priced gas. Since index-based pricing is prevalent in spot market sales and in intracompany price determination, it is not surprising that generators, at least on paper, paid the index price for gas. The commenters misconstrue the premise for Staff's alternate index proposal. The issue is not whether generators paid the index price, but rather (1) whether the index price was the result of manipulation, and (2) whether basing

mitigated market-clearing prices on the index emulates the result of a competitive market while providing generators with a reasonable opportunity to recover their costs. Staff finds that the index price was the outcome of market dysfunction and manipulation enabled by pipeline capacity shortages and, given the mechanics of the market-clearing price mechanism at high gas prices, over-recovers generator costs.

Staff ignored the fundamental reasons for high natural gas prices at the California border during the refund period.

Many commenters (NGSA, EPSA, Williams, TransAlta, Powerex, Anaheim, Burbank, SoCal, LADWP) argue that there are many well-documented reasons for the high natural gas prices in southern California during the refund period. Those reasons include the scarcity due to inadequate natural gas infrastructure (as noted by the CEC in its study of natural gas infrastructure issues); increased demand for gas due to low hydro reserves leading to more gas-fired generation; imbalance penalties on the SoCal system; and flaws in the wholesale and retail electricity market design, which spilled over into the gas market. They argue that Staff ignored those reasons and made a leap to gas market manipulation and manipulation of the reported indices.

Staff response:

Staff accepts that market manipulation was not the sole cause of high California spot gas prices. A portion of the increase in California border prices reflected legitimate scarcity. Nevertheless, Staff believes that unusually high demand and a shortage of pipeline capacity created the opportunity for manipulation, which did occur and did influence prices. The various forces and behaviors described in this Report cast a cloud over the gas market and taint the reported indices. The Commission need not find that *all* of the price differential between producing-area and California pricing points was due to manipulation to accept Staff's recommended alternate mitigation proposal. There is no fundamental policy reason that generators are entitled to higher gross operating profits simply because gas prices skyrocketed. By treating the transportation premium embedded in the gas price as a pass-through cost, generators are assured of a reasonable opportunity to recover their costs while at the same time assuring that a potential taint on gas prices is eliminated from the market-clearing price and generator profitability.

How should the MMCP account for scarcity?

In its Initial Report, Staff argued that the opportunity to recover gas costs over and above the production area price will allow parties to recover any costs reasonably associated with scarcity. In its August 13 request for comments on the Staff's Initial Report, the Commission asked the question: "What is an appropriate way to account for scarcity?"

Many commenters stress the point that Staff did not account for scarcity in its proposed methodology. SoCalGas and San Diego Gas & Electric Company argue that the only way to account for scarcity is to use the market prices relied on by market participants trading at arm's length. They state that no formula intended to recreate gas prices retrospectively can appropriately account for scarcity. As noted above, Dr. Roach suggests that the Commission use the actual prices that gas-fired generators paid for spot gas to construct a price, which would account for scarcity.

Staff response:

Most of the commenters implicitly assume that mitigated power prices should be based on spot gas prices regardless of the level of gas prices, or whether the gas price levels were artificially high. Staff disputes this notion. There is no fundamental principle that requires the Commission to allow artificially high gas input costs to produce proportionately higher generator gross operating profits. This is especially true when a significant portion of the higher gas costs was driven by market dysfunction and manipulation in addition to a scarcity of pipeline capacity.

Staff maintains that legitimate scarcity costs cannot be separated from the influence of market distortions affecting the California gas market. Further, it is not clear whether an effort to emulate the outcome of a competitive market should include the influence of abnormalities such as the Carlsbad rupture. In Staff's view, the use of the producing-area cost allowance provides generators with a reasonable opportunity to recover their costs. As shown above, basing the MMCP on the producing-area index plus transportation yields reasonable operating profit levels, more than sufficient to support investment in new generation.

Staff recognizes that the proposed methodology, which allows less efficient units to charge a higher price, could be construed as penalizing more efficient generating units, thus stifling investment in

more efficient generation. The long-term benefit of competitive electricity markets comes from the suppliers' incentive to invest in more efficient, cleaner generation in order to maximize its profits. More efficient units will earn greater profits by producing at a lower cost. However, given Staff's conclusion that the high natural gas prices reflected (in part) market dysfunction and manipulation, part of any profit earned by the more efficient units would be due to the higher prices resulting from dysfunction and manipulation, the cost of which would ultimately be borne by consumers. A price based on market dysfunction and manipulation does not send an accurate signal regarding the profitability of investment. Staff's proposed methodology strikes a balance between protecting customers from prices based on market manipulation and dysfunction and protecting suppliers' ability to earn a fair profit in a competitive market.

California Parties' concerns about fuel cost recovery

The California Parties argue that the Commission should not allow a cost-based recovery mechanism for fuel costs above the producing area allowance because this would mix market-based rate and cost-based recovery mechanisms. The California Parties assert that the Commission has already provided a cost-of-service alternative mechanism for those parties who find that the July 25 MMCP methodology provides insufficient revenue to cover their costs. The California Parties argue that the fuel recovery mechanism proposed in the August 13 Initial Report is flawed because (1) it would depend on unit heat rates, which vary with load, and some portion of that load is serving bilateral contracts rather than Cal ISO and Cal PX spot markets; (2) bids to the Cal ISO and Cal PX were not unit specific, thus making heat rate determinations problematic; and (3) more efficient generators may not need a fuel recovery allowance to remain profitable.

Staff response:

Staff submits that the proposed additional fuel cost recovery mechanism is a pragmatic adjustment to the market-based methodology prescribed by the July 25 Order. The cost-of-service alternative would still be available to generators or marketers who are not satisfied with the revised MMCP methodology. Since the proposed modification to the July 25 methodology would substantially reduce the MMCP below the cost of generating power using California spot market gas, the additional fuel cost recovery mechanism is needed for the market-based option to be fair and realistic.

With regard to heat rate determination, Staff does not agree that a generator should allocate its fuel consumption to different services at different loading levels. Staff proposes that a single heat rate for each 10-minute interval should apply to all services the generator provides. With regard to the concern that the Cal ISO and Cal PX bids were not unit specific, Staff asserts that the generators must make a showing of which units served the Cal ISO and Cal PX market in the Compliance filing phase of the refund proceeding. The California Parties will have an opportunity to review this submission and advise the Commission on their concerns at that time. With regard to the level of profitability of specific generators, Staff's analysis in this Report addresses generator operating profitability in detail. The proposed methodology reduces generator profitability but provides a reasonable opportunity to recover costs consistent with the goal of the price mitigation as discussed in the July 25 Order.

V. The Influence of Electricity Spot Prices on Electricity Forward Prices

Summary of Results

The vital link between the spot price and forward price for a commodity is the ability to store the commodity. In essence, someone can meet future needs by purchasing the commodity now and storing it for future consumption. As a result, the forward price that someone is willing to pay will approximate the cost of purchasing plus the carrying cost involved with stockpiling and net of the risk associated with not holding the physical commodity. Since electricity has few storage applications, we would expect to see little or no relationship between spot electric prices today and the forward price of electricity. Instead, forward prices should mostly reflect a buyer's expectations of prices in the future. Since natural gas is the marginal fuel for producing electricity in the West, forward gas prices should, in large part, explain forward electricity prices. Our analysis shows, however, that the forward power contracts negotiated during the period 2000–2001 in the western United States were influenced by then-current spot prices, presumably because spot power prices influenced buyers' and sellers' expectations of spot prices in the future. The influence of spot prices on forward prices was the greatest for forward contracts with the shortest time to delivery (1-2 years) and varied by location. While Staff has found a statistically significant relationship, the magnitude of the impact is limited (that is, the impact of spot power prices on long-term power prices is clearly not dollar-for-dollar). Rather, a reduction of about one-third in the price of a 2-year forward contract would require a finding that spot power prices were three times above the just and reasonable level.

Background

The relationship between electricity spot prices and long-term contract prices has been the subject of debate since Enron filed for bankruptcy in December 2001. Questions have been raised in Congress and the media about whether Enron manipulated the spot market to influence the West forward market.

The Commission's February 13, 2002 Order establishing the fact-finding investigation specifically directed FERC Staff to look into whether manipulated spot prices resulted in unjust and unreasonable long-term power sales contracts.

In addition, a number of utilities[1] filed complaints with the Commission alleging that dysfunctions in the California electricity spot markets caused long-term contracts negotiated in the bilateral markets in California, Washington, and Nevada to be unjust and unreasonable. The complainants seek the extraordinary remedy of contract modification. The Commission issued an Order on April 11, 2002 consolidating these complaints and set them for an evidentiary hearing.[2] Subsequently, additional complaints were set for hearing.

Two studies that estimated the electricity spot/forward price relationship were filed in testimony in the proceeding.

On July 2, 2002, Snohomish submitted Mr. Robert McCullough's Direct Testimony. Mr. McCullough alleges a link between short-term prices and the prices of long-term contracts.[3] Mr. McCullough's analysis found a large, significant correlation between prices for short-term and long-term contracts.

On August 27, 2002, Mr. McCullough's analysis was challenged by Mr. William W. Hogan and Mr. Scott M. Harvey.[4] Representing Morgan Stanley Capital Group, Inc., Mirant Americas Energy Marketing, L.P., American Electric Power Service Corporation, and Reliant Energy Services in the same proceedings, Mr. Hogan and Mr. Harvey testified that no significant correlation can be demonstrated between spot and long-term power prices.

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[1]Nevada Power Company (Nevada Power) and Sierra Pacific Power Company (Sierra Pacific), Southern California Water Company (SCWC), and Public Utility District No. 1 Snohomish County, Washington (Snohomish).

[2]Consolidated proceeding: *Nevada Power Company and Sierra Pacific Power Company v. Enron Power Marketing, Inc., El Paso Merchant Energy, and American Electricity Power Services Corporation; Nevada Power Company v. Morgan Stanley Capital Group, Calpine Energy Services, Reliant Energy Services, and Mirant Americas Energy Marketing, L.P.; Southern California Water Company v. Mirant Americas Energy Marketing, L.P.; and Public Utility District No. 1, Snohomish County, Washington v. Morgan Stanley Capital Group, Inc.*—Docket Nos. EL02-28-000, EL02-33-000, EL02-38-000, EL02-29-000, EL02-30-000, EL02-32-000, EL02-34-000, EL02-39-00, EL02-43-000, and EL02-56-000.

[3]Testimony of Robert McCullough, Exh. SNO-17.

[4]Prepared Answering Testimony of Scott M. Harvey and William W. Hogan, Exh. No. MSC-65.

Comparison of the Two Studies

McCullough used different econometric models than Harvey and Hogan to estimate the spot/forward price relationship.

McCullough used a simple regression model to estimate the relationship between electricity forward and spot prices. This model uses only two variables: an explanatory variable and a dependent variable. McCullough attempted to estimate how the change of electricity spot prices (explanatory variable) correlates with electricity forward prices (dependent variable). By running this simple regression model with NYMEX strip prices[5] and spot prices from *Energy Markets Report*, McCullough estimated that, at the Palo Verde trading hub, 51 percent of the variance in the forward power price can be explained by the variance in the spot power price, and at the California-Oregon Border (COB) trading hub it is 40 percent. McCullough concluded that the change in the daily price was very closely correlated to the change of the forward price.[6]

Harvey and Hogan made several refinements to the McCullough analysis. First, they included forward gas prices and other independent variables designed to capture monthly and seasonal effects in their regression analysis. Second, they performed several analyses using alternative measures of forward power prices including NYMEX futures prices and forward prices reported by TFS, a major independent broker. Third, they employed econometric techniques specifically designed to address time-series data with "serial correlation."[7] Their analyses generally show small and statistically insignificant impacts of spot power prices on forward power prices.[8]

Neither study has the benefit of reliable data on long-term power sales contracts in the West during 2000–2001. There was little or no transaction volume in the NYMEX electricity futures market after February 2000. The electricity futures closing prices published by NYMEX until the product was delisted in February 2002 were not based on actual trading on the exchange. NYMEX maintained its index by surveying prices of bilateral trades.

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[5]NYMEX strip prices are an average of the daily settlement prices of the next 12 months of futures contracts.
[6]Testimony of Robert McCullough, Exh. SNO-17, pg. 86-87.
[7]Serial correlation is discussed at more length in Appendix V-D.
[8]Prepared Answering Testimony of Scott M. Harvey and William W. Hogan, Exh. No. MSC-65, p. 139, line 22 to p. 140, line 2.

Staff's Analysis

To help resolve the debate on this important issue, Staff performed its own statistical analysis with the help of an independent outside consultant, Robert S. Pindyck,[9] a nationally recognized econometrician with a specialty in energy futures markets, and consultants from Analysis Group/Economics. Our methods, data, models, and results are presented as follows: the basic economic logic and statistical methods that Staff employed, the data that Staff relied on for the analysis, the regression model used in detail, and the main results. Detailed results are provided in the appendices to this chapter.

Basic Economic and Statistical Methodology

Economics

For a storable commodity, such as crude oil, there is a clear relationship between spot and forward (or futures) prices that depends on the flows of benefits to producers and consumers from holding inventories.[10] Because of electricity's limited storability, the relationship between spot and forward prices is not as clear. Instead, forward power prices should largely reflect expectations of future demand and supply conditions.

Expectations, however, are often difficult to measure. In electricity markets, forward prices for fuel can provide an important measure of expectations about future electricity costs. In the western United States, natural gas is the marginal fuel for electricity in the short term, particularly in California and even in the Northwest when hydro water levels are low (as they were in 2000–2001), and in the long term for the construction of new generating capacity. As a result, forward gas prices should help explain forward electricity prices to the extent that prices reflect costs. The futures market for gas delivered to Henry Hub provides transparent signals about future input prices. Forward prices

[9] Robert S. Pindyck is a professor of Economics and Finance, Sloan School of Management, Massachusetts Institute of Technology.

[10] See, for example, B. Routledge, D. Seppi, and C. Spatt, "Equilibrium Forward Curves for Commodities," *The Journal of Finance*, v. LV, no. 3, June 2000, pp. 1297-1338, and R. Pindyck, "The Dynamics of Commodity Spot and Futures Markets: A Primer," *The Energy Journal*, v. 22, no. 3, June 2001.

for delivery of gas to specific locations in the West are less transparent. Nonetheless, market participants had access to forward market price quotations for gas to be delivered in the western United States, and could use these to project likely power prices.

In power markets, a relationship between spot and forward prices can exist when current spot prices convey information about spot prices in the future. For example, if one component of the current spot price represents market "dysfunction," market participants might use current spot prices to formulate expectations about future dysfunction.

Statistical Methodology

We tested the relationship between forward and spot power prices using multiple linear regression, because there are many factors that potentially explain forward power prices. Multiple linear regression is a statistical method for decomposing the influence of different factors (independent variables) on a variable of interest (dependent variable). We seek to explain forward power prices as a function of current spot prices, forward gas prices, and seasonal factors. The forward gas price is the fundamental factor that drives the forward power price in the western United States because gas is the short- and long-term marginal fuel. Controlling for the forward gas price, we can test whether the current spot price can explain any portion of the variation in forward power prices.

We also include dummy variables to capture seasonal effects.[11] Many seasonal factors influence energy markets. On the supply side, hydroelectric resources vary seasonally. On the demand side, weather varies seasonally and influences consumption. A spot price that appears high in the spring may be normal for the summer. By including season dummy variables, we attempt to isolate the effect of abnormal spot price movements on forward prices.

Most of our results are based on ordinary least squares (OLS) regression, but we employed several other linear regression techniques to address specific econometric issues.

[11]Dummy variables are the standard way of representing binary (yes/no) effects in regressions. The dummy variable for a season takes the value of 1 if the observation in question occurs during that season and is 0 otherwise.

Data

We requested data from wholesale sellers in the West on their electricity transactions during 2000 and 2001.[12] The data request was targeted at all marketers active in the West and compliance with the request was nearly universal.

The responses to the Staff data request were provided in electronic templates. These responses left some room for interpretation. As discussed below, we spent a considerable amount of effort in comparing different parties' responses and verifying responses against written contracts and other documentation provided by most, but not all, sellers. To the best of our knowledge, this is the most comprehensive database of forward power contracts for the period and locations in question.

Sample Size

In our March 5, 2002 Data Request, we asked market participants to report all of their short-term, monthly, and long-term energy sales. We defined short-term sales as transactions of a week or less. Monthly sales were defined as transactions with a period of 1 month. Long-term sales were defined as transactions with a contract duration of 1 year or more. We focused our analysis exclusively on long-term contracts.

The data reflect contracts for delivery during peak, off-peak, and all hours. The majority of contracts in the database are for peak deliveries. In addition, by definition, peak hours cover the periods of highest demand and hence are the most economically significant. Therefore, our analysis relies on contracts for peak delivery exclusively.

Staff received data on long-term transactions (a year or more in duration) that either included the period 2000–2001 or were signed after January 2000. We included in our analysis contracts signed from the beginning of 2000 through March 2002, when the data request was issued. For this 27-month period, we have 2,652 unique contracts for the 5 major delivery locations on which we focus our analysis.

We considered two major subperiods: the period from January 2000 leading up to and including the period of high Western power prices, and the period after June 19, 2001 (when West-wide price mitigation

[12]Staff data request to all jurisdictional sellers and all nonjurisdictional sellers in the West issued March 5, 2002 in Docket PA02-02.

went into effect)[13] through March 2002. As Table V-1 demonstrates, the number of observations varies by location and period. The first 18 months account for 1,066 observations, or 40.2 percent of the total. The last 9 months account for 1,586 observations, or 59.8 percent of the total.

Table V-1. Sample Size by Region and Period Definition

Hub	1/1/00 – 6/30/01	7/1/01 – 3/31/02
Mid-C/COB	199	163
NP15	136	429
SP15	314	635
PV	417	359
All Hubs	1,066	1,586

Hubs and Duration Classes

Our analysis considered contracts at the five main trading hubs in the West—COB, Mid-Columbia (Mid-C), Palo Verde (PV), and California Independent System Operator (ISO) zones NP15 and SP15. We treat Mid-C and COB as a single hub based on the high correlation of prices at these two locations.[14]

As discussed above, one key issue that we sought to address is how the relationship between spot and forward power prices changes with time to delivery. To simplify our analysis of this issue, we grouped contracts into time-to-delivery bins.[15] We initially assigned contract duration classes corresponding roughly to the time between each contract's signing date and the midpoint of its delivery window rounded to the nearest year—e.g., a contract for 10 years of deliveries signed and commencing today was assigned a duration of 5.

[13]The June 19, 2001 Order marks the date when all sellers in the western United States were subject to a must-offer requirement and price caps. See 95 FERC at 62, 558.

[14]In addition, we performed statistical analyses in which we tested whether the relationship between spot and forward prices at the two locations was different. We could never reject the null hypothesis that the relationship at the two hubs was the same.

[15]Alternatively, we could have used more complicated nonlinear regression techniques in which we allowed various model coefficients to depend on time to delivery.

Forward Gas and Electricity Spot Price Data

We relied on two different commercially available databases for our independent variables. We obtained data on forward gas prices for various locations in the West from TFS, an independent power and gas broker[16] that has collected the most complete forward gas quotes covering the period and locations in question. Staff also obtained the forward gas prices that Williams and Enron used to price their own trades. Limited forward gas prices from Morgan Stanley are publicly available.[17] We have verified that the TFS quotes are broadly consistent with the forward curves used by these major market participants.[18] It is useful to know that expectations about forward gas prices were roughly similar among major market participants. For our analysis, however, we used TFS data because of their independence.

The long-term transaction data used in our analysis are for periods of 1 year or more. The TFS forward gas quotes are for delivery periods of 1 month. In our regression analysis, we use averages of these monthly gas prices calculated over the entire delivery period of each forward power contract.

Because gas and electricity are traded at slightly different locations, we had to decide which forward gas price to assign to the forward power contracts at each location. Our assumed correspondence is as follows:

Power Trading Hub	Relevant Gas Hub Price
SP15	Topock
NP15	Malin
COB	Malin
Mid-Columbia	Sumas
Palo Verde	Permian

For spot power prices, we used the on-peak firm power prices reported by Bloomberg. For the two delivery locations inside the California ISO (NP15 and SP15), we compared the Bloomberg prices to the average of the hourly day-ahead prices for peak hours of the California Power Exchange (PX) during the period when the PX was still operating. The Bloomberg prices are consistent with the PX prices.

[16]Information about TFS Brokers is available at http://www.tfsbrokers.com/.
[17]See Harvey and Hogan, op. cit., note 4.
[18]The details of this comparison are discussed in Appendix V-B.

Audit Process and Results

We performed a number of initial quality checks on the transaction data we collected and contacted respondents to resolve problems with the data. We undertook a comprehensive audit of the filed data by comparing reported transaction data with reported actual contracts and contract confirmations.[19]

We audited all contracts that were supported with appropriate documentation. Auditable transactions make up about 59 percent of the total number of transactions.[20] Once we verified the sales data for these auditable transactions, we compared the results of a statistical analysis that used just the audited data with the results of an analysis that used all transactions.[21] The regression results using the audited-only transaction data and the all-transaction data generally are not significantly different statistically. Therefore, we concluded that including the remaining unaudited data did not change our results and decided that further review of the data was not necessary.

Regression Specification

Definition of Sample Period

Our primary analysis covers the 18-month period from January 2000 through June 2001. The long-term transaction data we collected cover the period from January 1999 to March 2002. We focused our attention on the period through June 2001 because of the West-wide price mitigation put in place beginning June 19, 2001. We examined the period after June 2001 separately to assess whether the relationship between spot and forward power prices changed with this change in market structure.

[19]The details of this audit are discussed in Appendix V-A.
[20]Table V-A2 in Appendix V-A shows the breakdown of documented and undocumented contracts by seller.
[21]This analysis is shown in Appendix V-A, Tables V-A3 and V-A4.

Basic Equation

Our regressions have the following general form:

$$\log(FP_{ijt}) = a_{ij} + b_{ij}\log(SP_{it}) + c_{ij}\log(FG_{ijt}) + q + e_{ijt} \quad (1)$$

For example, FP_{ijt} is the forward electricity price in year 2003 (time t) for delivery at Palo Verde (location i) in year 2008 (time j), SP_{it} is the spot price at Palo Verde in 2003, and FG_{ijt} is the forward gas price in 2003 for delivery at Permian in 2008. Factor q controls for seasonal variations[22] and e_{ijt} captures any remaining unexplained component of FP_{ijt}.

We estimate equation (1) in logs. A log specification has a number of desirable properties in the context of estimation such as ours. In particular, it captures a constant proportional relationship between the dependent and independent variables over a wide range of prices. For example, it assumes that an increase in spot power prices from $100 to $110 has the same percentage impact on forward power prices as an increase from $10 to $11.[23] When equation (1) is specified in logs, the coefficient on the spot electricity price, b_{ij}, is the elasticity of forward electricity prices with respect to spot electricity prices. The elasticity is the ratio of the percentage change in one variable with respect to the percentage change in another variable.

Aggregation

As discussed above, we examined data for five hubs and a number of duration classes. After some preliminary analysis, we decided to treat COB and Mid-Columbia as a single hub. In addition, we were able to obtain stable and precise results by aggregating the duration into three classes: (1) contracts with average times to delivery of less than 2

[22]We define seasons quarterly (i.e., spring is March to May, summer is June to August, fall is September to November, and winter is December to February).

[23]There are technical reasons for preferring a log specification. The error for regressions based on price data usually is thought to be proportional to price, i.e., a $10 error for a $100 price is equivalent, by some measure, to a $1 error for a $10 price. If the error is in fact proportional to the level of prices, specifying the estimation in logs guarantees that the individual elements of the error are homoscedastic, i.e., equal in variance, and hence that our parameter estimates are unbiased and efficient. In other words, a log specification guarantees that our parameter estimates are as accurate and precise as possible. If the elements of the error are not homoscedastic, not only are parameter estimates from OLS regression inefficient, but estimated standard errors are biased and hence can lead to incorrect statistical inference. For a discussion of these issues see R. Pindyck and D. Rubinfeld, *Econometric Models and Economic Forecasts*, 4th edition, New York: McGraw-Hill, 1998, pp. 146-152.

years, (2) contracts with average times to delivery of 3 to 4 years, and (3) long-term contracts with average times to delivery of 5 years or greater.[24]

Instrumental Variables

Statistical inference using OLS regression rests on a set of assumptions. One assumption is that the error, i.e., the component of the dependent variable that is not explained by the statistical model, is uncorrelated with any of the independent variables. Given that forward gas and power prices are simultaneously determined, i.e., the forward gas price is a major input to the generation of electricity and the generation of electricity is a major source of demand for gas, this assumption may not hold in our case. Hence, estimation of equation (1) may show a correlation between forward gas and power prices, but that correlation cannot be interpreted as causal.

We address this econometric issue using a technique known as instrumental variables (IV) estimation,[25] which attempts to break the circle of simultaneity by using proxy variables, or instruments, that are not plagued by the same simultaneity problems. "Good" instruments have two characteristics: (1) they are exogenous, i.e., they are uncorrelated with the error, and (2) they are correlated with the variable for which they are instruments.

Our instrument for the forward gas price was the contemporaneous forward gas price at Henry Hub. Henry Hub, near the production basins along the Gulf Coast, is a large and liquid trading hub. Gas originating at or near Henry Hub has a variety of uses throughout the United States, including electricity generation, chemical processing, and heating. Demand for gas for electricity generation in the western United States should have relatively little impact on Henry Hub prices, and the Henry Hub forward price therefore meets the first criterion of a good instrument. With respect to the second criterion for a good instrument, because there is some transportation between Henry Hub and locations in the West, Henry Hub prices are usually correlated with prices in the West.

Absent the ability to store electricity, there is no reason to believe that current spot power prices are influenced by expectations about future gas and power prices as reflected in forward prices, so we treat spot power as exogenous in our estimation, i.e., we do not instrument for it.

[24]Detailed results based on the disaggregated data are presented in Appendix V-D.
[25]See R. Pindyck and D. Rubinfeld, op. cit., Chapter 7.

Under the assumption that a set of instruments is "valid," the extent of any bias due to simultaneity can be assessed by comparing instrumental variables and ordinary least squares parameter estimates.[26] When these estimates are close, any presumed simultaneity problem is negligible. In the next section, we present the regression results using both ordinary least squares with and without instrumental variables. Our estimates tell us that any simultaneity problem is negligible. Therefore, we believe that the results using the ordinary least squares method are appropriate for use in the long-term power contract proceeding.

Regression Results

Our analysis is summarized below. We performed separate analyses for the periods before and after West-wide price mitigation was introduced. The subsequent section discusses a few minor extensions and modifications of our analysis.

"During" Period Results Summary

We found that spot power prices influence forward power prices in a statistically significant and economically important way. In the simplest formulation, in which we estimated a single average elasticity for all contracts of different times to delivery and different locations, the elasticity is 0.07. This formulation masks substantial variation in the elasticity by region and time to delivery—the longer the contract duration, the lower the impact of spot market prices upon the forward price.

Table V-2 shows results based on an analysis that combines data from all five trading hubs, and shows the effect of time to delivery. As expected, the effect declines with time to delivery. Using ordinary least squares, the point estimates of the spot power coefficients range from 0.05 to 0.33. These estimates imply that for each 10-percent increase in the spot price, forward power prices rose by approximately 0.5 percent to 3.3 percent. These effects are larger for contracts with short times to delivery than contracts with longer times to delivery.

[26]This comparison can be formalized as a Hausman test. See R. Davidson and J. MacKinnon, *Estimation and Inference in Econometrics*, New York: Oxford University Press, 1993.

Table V-2. Spot Power Coefficient by Time-to-Delivery Class: "During" Period

Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Number of Observations
	Spot Power Coefficient	Standard Error	t-Statistic	Spot Power Coefficient	Standard Error	t-Statistic	
1-2 Years	0.33	0.03	9.80	0.27	0.04	6.34	451
3-4 Years	0.12	0.02	6.54	0.11	0.02	5.73	398
5-8 Years	0.05	0.01	3.36	0.08	0.01	4.18	217

The regression results with instrumental variables are generally close to those without instrumental variables. This may indicate that simultaneity is not a significant concern. Alternatively, the results may indicate that, even if the forward gas price is endogenous, it does not bias our estimate of the coefficient on spot power.

Table V-2 gives point estimates, standard errors, and t-statistics for the spot power elasticities. The standard error measures the precision of the estimate, i.e., the smaller the standard error the more precise the estimate. The standard error of the OLS estimate for duration class 1-2 years is 0.03. A one standard error band around the point estimate defines a 68-percent confidence interval, i.e., there is a 68-percent probability that the "true" elasticity (i.e., the one we are attempting to estimate) lies between 0.30 (0.33 – 0.03) and 0.36 (0.33 + 0.03). Naturally, our best estimate is in the middle of this range.

The t-statistic, which is commonly used to assess whether a parameter estimate is statistically significantly different from zero, is simply the point estimate divided by the standard error. Statistical significance is usually measured at the 90- or 95-percent confidence level. A coefficient is considered statistically significant at the 95-percent confidence level if the value of zero is not within a band around the coefficient value of 1.96 standard deviations. For example, for the OLS for duration class 1-2 years, the 95-percent confidence band is .33 plus or minus (1.96 times .03 = .0588) or between .2712 and .3888. All of the parameter estimates in Table V-2 are statistically significant at the 95-percent level.

Table V-3 shows disaggregated results by hub. The OLS and IV coefficients are generally close considering the precision of the estimates. Most estimates of the spot power coefficient are statistically significant at the 90-percent level or higher. For most hubs, we observe the expected pattern of the magnitude of the coefficient on spot power falling with time to delivery.

The significance of these results is weakest for contract duration class 5-8. Only for the Palo Verde hub are these results significant at the 95-

percent level. For the other hubs in the 5-8 class, the estimates are not significant at the 90-percent level.

Since the effects in Table V-3 seem to vary by location, any policy conclusions should be based on the coefficient for the relevant location.

Table V-3. Spot Power Coefficient by Time to Delivery and Hub: "During" Period

Hubs	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Number of Observations
		Spot Power Coefficient	Standard Error	t-Statistic	Spot Power Coefficient	Standard Error	t-Statistic	
Mid-C/ COB	1-2 Years	0.38	0.09	4.16	0.21	0.13	1.66	101
	3-4 Years	0.13	0.04	3.12	0.19	0.05	3.58	62
	5-8 Years	(0.00)	0.03	(0.13)	(0.01)	0.03	(0.41)	36
NP15	1-2 Years	0.22	0.13	1.64	0.29	0.14	2.10	40
	3-4 Years	0.14	0.04	3.16	0.14	0.05	3.01	72
	5-8 years	0.06	0.05	1.33	0.06	0.05	1.20	24
PV	1-2 Years	0.38	0.06	6.58	0.40	0.06	6.90	221
	3-4 Years	0.09	0.04	2.37	0.08	0.04	2.14	122
	5-8 years	0.07	0.02	3.36	0.07	0.02	3.35	74
SP15	1-2 Years	0.23	0.08	2.99	0.14	0.08	1.69	89
	3-4 Years	0.07	0.03	2.33	0.07	0.03	2.28	142
	5-8 years	0.04	0.03	1.29	0.04	0.03	1.35	83

"After" Period Results Summary

Next, we examine whether the relationship between spot and forward power prices changed after the spot market prices stabilized following the introduction of West-wide price mitigation. Tables V-4 and V-5 show these results for the July 2001 to March 2002 period in the same format as Tables V-2 and V-3. They generally show a persistence of the effects found during the crisis, i.e., statistically significant positive elasticities of the forward price with respect to the spot price.

Table V-4. Spot Power Coefficient by Contract Duration Class: "After" Period

Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Number of Observations
	Spot Power Coefficient	Standard Error	t-Statistic	Spot Power Coefficient	Standard Error	t-Statistic	
1-2 Years	0.12	0.02	7.15	0.13	0.02	7.41	887
3-4 Years	0.12	0.02	7.12	0.14	0.02	7.35	473
5-8 years	0.15	0.02	6.83	0.17	0.02	7.22	226

TableV-4 does not show the decline in elasticity with contract duration observed in Table V-2. On average, the point estimates are smaller than those in Table V-2.

The results in Table V-5 show elasticities that are sometimes smaller and less significant than those in Table V-3, but in other cases the opposite is true. There are regional variations. The SP15 elasticities have larger t-statistics in the "after" period. Several large elasticities estimated for shorter term contracts (0.35 for Mid-C/COB and 0.38 for PV) in Table V-3 are absent from Table V-5. The largest elasticity after the price mitigation is for class 3-4 years at Mid-C/COB. It is unclear why this is the case.

Table V-5. Spot Power Coefficient by Hub and Duration: "After" Period

Hubs	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Number of Observations
		Spot Power Coefficient	Standard Error	t-Statistic	Spot Power Coefficient	Standard Error	t-Statistic	
Mid-C/ COB	1-2 Years	0.03	0.05	0.67	0.05	0.05	1.05	91
	3-4 Years	0.38	0.08	4.83	0.37	0.08	4.46	45
	5-8 years	0.14	0.07	1.94	0.17	0.08	2.16	27
NP15	1-2 Years	0.08	0.02	3.17	0.08	0.02	3.43	204
	3-4 Years	0.02	0.02	0.90	0.03	0.02	1.17	145
	5-8 years	0.02	0.03	0.70	0.03	0.03	0.96	80
PV	1-2 Years	0.10	0.06	1.74	0.10	0.06	1.74	197
	3-4 Years	0.02	0.05	0.53	0.03	0.05	0.57	106
	5-8 years	0.13	0.06	2.30	0.13	0.06	2.27	56
SP15	1-2 Years	0.07	0.02	3.26	0.06	0.02	3.04	395
	3-4 Years	0.09	0.02	3.82	0.09	0.02	3.88	177
	5-8 years	0.09	0.04	2.29	0.09	0.04	2.28	83

The results for the "after" period show persistence in the relationship between spot and forward power prices. This indicates that the process for forming expectations that developed during the crisis period did not instantly disappear or reverse itself following the implementation of the spot power mitigation measures required by FERC's June 19, 2001 Order.

We have conducted a number of other tests that are described in more detail in Appendix V-C. These are variations on the basic equation using different pooling approaches. The results are broadly consistent with Tables V-2 to V-5. We also report more disaggregated results in this appendix. Finally, we address another econometric issue in Appendix V-D, namely, whether serial correlation affects the estimates and their precision. In Appendix V-D, we show results indicating that this is not the case.

Interpreting Regression Results

To illustrate the implications of the estimated spot power elasticities on forward power prices, we construct some stylized examples.

For each of our time-to-delivery classes, we calculated the average forward power price (FP) for all Mid-Columbia and Palo Verde contracts signed between January 1, 2001 and March 31, 2001. To apply the estimated spot power elasticities from Table V-3, we need to assume spot power prices were distorted and by how much. We consider two hypothetical cases: 100-percent and 200-percent distortion.

Hypothetical spot power price distortions of 100 percent and 200 percent can be roughly justified with reference to the implied system heat rate calculated in Table V-6 below. The implied system heat rate is simply the spot power price divided by the spot gas price and is a convenient measure of market performance that is sometimes used by traders. Under normal conditions, it would typically be in the range of 10,000 to 11,000 Btu/kWh, representing the thermal efficiency of older steam boilers that typically serve marginal demand in California. Under short supply market conditions the implied system heat rate might be higher than this level. For a useful point of reference, we have calculated the relevant average of "clearing" heat rates that have been used in the California refund case.[27] For the same period, these heat rates are in the 15,000 to 17,000 Btu/kWh range during peak demand periods. These values represent very inefficient peaking plants that operated for many peak hours during this period. In comparison, the implied system heat rate for Mid-C and PV in Table V-6 is 2 to 3 times higher.[28] This suggests that 100-percent to 200-percent spot price excess may not be unreasonable.

[27] See Exhibit ISO-6 in the refund case. This exhibit was originally protected; however, the protection was removed by Administrative Law Judge Birchman on December 16, 2001.

[28] The data in Table V-6 are simple averages over the period between January 1, 2001 and March 31, 2001.

In Table V-6, we calculate the mitigated forward power price (MFP) for each combination of hub and assumed level of spot price distortion using the following equation:[29]

$$MFP = FP \times (1+\gamma)^{-\beta}$$

where γ is the assumed percentage spot price distortion and β is the estimated elasticity.

Table V-6. Impact of Estimated Spot Power Elasticity on Forward Price of Power (January 1, 2001 – March 31, 2001)

Hub	Time-to-Delivery Class	Average Spot Power Price ($/MWh)[30]	Average Spot Gas Price ($/MMBtu)	Implied System Heat Rate (Btu/kWh)	Assumed Spot Power Elasticity β	Assumed Spot Power Distortion γ	Average Forward Power Price ($/MWh) Observed[31] FP	Average Forward Power Price ($/MWh) Mitigated MFP
Mid-C/ COB	1-2 Years	284.21	6.30 (Sumas)	45,113	0.38	200%	153.75	101.28
	3-4 Years				0.13		84.02	72.84
	5-8 years				-		54.86	54.86
	1-2 Years				0.38	100%	153.75	118.15
	3-4 Years				0.13		84.02	76.78
	5-8 years				-		54.86	54.86
PV	1-2 Years	220.88	6.25 (Permian)	35,341	0.38	200%	123.28	81.21
	3-4 Years				0.09		71.43	64.71
	5-8 years				0.07		52.68	48.78
	1-2 Years				0.38	100%	123.28	94.73
	3-4 Years				0.09		71.43	67.11
	5-8 Years				0.07		52.68	50.18

The calculations in Table V-6 are intended to indicate plausible applications of the statistical results. When we use our estimates of the regression coefficients from Table V-3 under the assumption of 100- to 200-percent spot price excess, we get substantially lower forward

[29]Starting from the main regression equation $FP = \alpha \times SP^{\beta} \times FG^{\delta}$ (expressed in equation (1) in logarithmic form), we assume that the observed spot power prices are γ percent inflated over the mitigated spot power prices (MSP), or mathematically, $SP = MSP \times (1 + \gamma)$. Substituting for SP we then get

$$MFP = \alpha \times MSP^{\beta} \times FG^{\delta} = \alpha \times \frac{SP^{\beta}}{(1+\gamma)^{\beta}} \times FG^{\delta} = FP \times (1+\gamma)^{-\beta}$$

[30]We calculated the average daily peak spot power prices using historic Bloomberg quotes from January 1, 2001 to March 31, 2001.

[31]The average observed forward prices were estimated using the actual long-term sales contract data for contracts signed during the period January 1, 2001 to March 31, 2001.

contract prices for time-to-delivery class 1-2. Under the 200-percent spot power prices excess case, the implied reduction in contract price is about one-third. For the 100-percent spot power inflation case, the reduction is about 23 percent for this class. These effects are much smaller for time-to-delivery classes 3-4 and 5-8.

Conclusion

Our analysis shows that there is a statistically significant relationship between spot and forward power prices during the period from January 1, 2000 through June 30, 2001. This relationship is somewhat unexpected in a market for a commodity with little storability and reflects the fact that market participants used current spot prices to form expectations about future spot prices during the period in question.

Although estimated elasticities vary by hub and time to delivery, the results show that the influence of spot on forward power prices declines with longer times to delivery. This pattern is consistent with the notion that current spot prices convey more information about spot prices in the near future than the distant future.

If, as we maintain in earlier chapters, spot power prices were distorted, these results imply that the price distortion flowed through to forward power prices, particularly those for contracts of short (1-2 years) time to delivery.

Our analysis shows clearly (Tables V-2 and V-3) that the elasticity of forward power prices with respect to spot power prices is much greater for forward contracts of 1-2 years (about 33 percent) than for contracts of 3-4 years (about 12 percent) and is very small for contracts of longer average time to delivery.

Because spot gas prices influence spot power prices, the manipulation of spot gas prices could have led to power prices that were distorted above and beyond the levels established in the refund hearing. According to the analysis in this chapter, this additional distortion would have influenced forward power prices. The magnitude of such an effect can be calculated in the manner illustrated in Table V-6.

In addition, because spot and forward gas prices are linked through arbitrage, spot gas manipulation may have influenced forward power prices by inflating the price of forward gas. We have made no estimate of the magnitude of this second effect.

Recommendation

Given the finding that forward power prices were distorted and a detailed statistical analysis providing estimates of the extent of the distortion based on a certain level of distortion in spot power prices, we present the following recommendation:

- For contracts that are subject to a just and reasonable standard of review in the ongoing complaint proceeding (see footnote 2), the Commission should send this analysis to the Administrative Law Judges to use as they see fit to resolve the complaints.

VI. Trading Strategies, Economic Withholding, Inflated Bidding, and Other Anomalous Activities

Initial Recommendations

In this chapter, Staff will conclude its analysis of the Enron trading strategies (first discussed in the Initial Report) and describe further developments and investigations since the Initial Report was issued. This chapter builds upon the Cal ISO report released on January 6, 2003, which identified potential transactions and parties that may have used the Enron trading strategies. This chapter also discusses potential economic withholding during the summer of 2000. We discuss evidence indicating that Enron worked in concert with other entities, both inside and outside California, to implement these strategies in ways that manipulated market outcomes. In this regard, Enron's business model is discussed along with Staff's recommendations.

We also discuss whether the Enron trading strategies, underscheduling, economic withholding, and inflated bidding fall within the scope of the antigaming and/or anomalous market behavior provisions in the Cal ISO's and Cal PX's Market Monitoring and Information Protocol (MMIP). The MMIP is part of both the Cal PX and Cal ISO tariffs, which have been on file with the Commission since the Cal ISO began operations in April 1998. Staff recommends that the Commission issue orders to show cause why these behaviors did not constitute "gaming" in violation of the MMIP, with disgorgement of unjust profits associated with the violations or other appropriate remedies. Such disgorgement would be in addition to any refunds owed to establish just and reasonable rates in the California Refund Proceeding.

The preponderance of evidence reviewed by Staff during this investigation indicates that Enron and its affiliates intentionally engaged in a variety of market manipulation schemes that had profound adverse impacts on market outcomes. Due to this overwhelming evidence, Staff recommends that the Commission issue an order to show cause why its market-based rate authorizations and blanket certificate authority should not be revoked. This order should cover Enron and its affiliates with the exception of Portland General Electric Company, which is the subject of an ongoing investigation in Docket No. EL02-114-000. Staff recommends that such revocation be made effective prospectively so that any preexisting contracts are not affected.

Background

On May 6, 2002, Enron's Washington, DC counsel provided the Commission with three internal memoranda, two of which date from December 2000, that describe certain trading strategies employed by Enron's electricity traders in the West. Enron's counsel informed Staff that Enron's Board of Directors had voted to disclose the documents and to waive all claims of privilege. The Commission made these documents publicly available on the Web site for Docket No. PA02-2-000 within hours of receiving them.

Staff immediately requested followup information from Enron to better understand the trading strategies discussed in the memoranda, including Enron's receiving transmission congestion payments without actually relieving any congestion. Among other things, Staff sought any comparable memoranda that discuss trading strategies for natural gas products. Finally, the data request asked Enron to provide all correspondence related to the subject matter of the memoranda.

The documents provided by Enron indicated that traders from other companies were also employing several of the trading strategies discussed in the memoranda. In order to pursue this issue, on May 7, 2002, Staff issued a notice to all sellers of wholesale electricity and/or ancillary services in the West, informing them that Staff would soon be sending them a data request seeking information about their use of the trading strategies discussed in the Enron memoranda, and directing them to preserve all documents related to such trading strategies.

On May 8, 2002, Staff issued a data request to more than 130 sellers of wholesale electricity and/or ancillary services in the West during 2000–2001, with a due date of May 22, 2002. This data request contained a series of requests for admissions in which an officer of each company was required to admit or to deny, under oath, whether his or her company had engaged in specific activities described in the request. The specific activities were based on the trading strategies discussed in the Enron memoranda; in addition, there was an additional request asking the corporate officer to admit or deny, under oath, whether the company had engaged in any other trading strategies. The data request also sought production of all internal documents relating to trading strategies that the company may have engaged in during the relevant time period, including correspondence between companies, reports, and opinion letters. Staff also requested specific information in regard to any megawatt laundering transactions between any of these sellers and Enron.

This data request required a senior officer of the company to state, in an affidavit and under oath, that he or she conducted a thorough investigation of the company's trading activities in the West during 2000–2001 and that the information being provided in response to the data request was complete and accurate to the best of that person's knowledge and belief.

In our Initial Report, Staff concluded that, while the exact economic impact of the trading strategies is difficult to determine precisely, these now infamous trading strategies have adversely affected the confidence of markets far beyond their dollar impact on spot prices. Even those trading strategies that are not anticompetitive have been viewed by customers as clever exploitations of overly complex rules by companies that do not account for the impact of their decisions on prices and customers. Market participants from all sectors of the industry may have engaged in these trading strategies along with Enron, and in trading strategies of their own, including nonpublic utility entities such as municipal and governmental agencies in California and jurisdictional public utilities (including power marketers).

Staff's initial review of the evidence indicated that Enron, as a corporate entity, displayed great eagerness to experiment with all aspects of market rules and protocols in an effort to "game the system" or to simply provide false information. In fact, shortly after the issuance of our Initial Report, Enron's former chief West Coast trader, Timothy N. Belden, pleaded guilty to Federal fraud charges for his role in implementing these trading strategies. Enron's corporate culture fostered a disregard for the American energy customer; the success of the company's trading strategies, while temporary, demonstrates the need for explicit prohibitions on harmful and fraudulent market behavior and for aggressive market monitoring and enforcement.

In a market environment, one expects that traders, working within Commission-approved market rules, will use various strategies in an effort to maximize profits. But a fundamental aspect of some of the Enron trading strategies was the deliberate use of false information. A market cannot operate properly without accurate information. Implicit in Commission orders granting market-based rates is a presumption that the power marketer's behavior will not involve fraud or deception. For this reason, our Initial Report recommended that the Commission explicitly prohibit the use of false information as a condition for granting all market-based rate authorizations. Staff recommends that this condition also be added to all open access transmission tariffs.

Overview of the Cal PX and Cal ISO Operations

The Enron trading strategies and Enron's use of them to game the system are best understood in the specific context of Western energy markets. Thus, we provide a brief overview of the Cal PX and Cal ISO operations and trading rules.

The Cal ISO operates much of the transmission grid in California and is responsible for all real-time operations, such as continually balancing generation and load and managing congestion on the transmission system it controls. In California, a certified scheduling coordinator is the intermediary between the Cal ISO and the ultimate customer. Under California's restructuring legislation, the Cal PX was created primarily to operate two markets in which energy was traded on an hourly basis. These were the day-ahead and day-of markets. These markets established a single clearing price for each hour across the entire Cal ISO control area, provided there were no transmission constraints. Where transmission congestion existed, a separate clearing price was established for each transmission constrained area or zone in California. Each individual zonal clearing price was based on adjustment bids submitted by buyers and sellers. The adjustment bids represented the value to an entity of increasing or decreasing (i.e., adjusting) its use of the system. In essence, this is a redispatch of the system to deal with congestion.

California's restructuring plan required the three California public utilities (SoCal Edison, San Diego, and PG&E) to sell all of their generation resources into the Cal PX and to buy all of their energy needs from the Cal PX. This made the Cal PX by far the largest scheduling coordinator in California, representing at times close to 90 percent of the load served by the Cal ISO grid. This requirement that the three public utilities exclusively use the Cal PX was critical in the restructuring program, since this was how the three public utilities were to calculate savings from using the new market structure and apply those savings to recover their stranded costs.

Under the California restructuring rules, the three California public utilities were both buyers and sellers in the Cal PX. The prices paid for buying back their own resources through the Cal PX served to value those resources for stranded cost purposes. As long as the three public utilities paid less than the frozen retail rates, they used the difference to write off stranded costs. As noted in the Commission's December

15, 2000 Order, stranded cost estimates show PG&E collected $8.3 billion, SoCal Edison collected $9.3 billion, and San Diego fully recovered its stranded costs early in 2000. This formula broke down, however, when the public utilities had to buy back their resources at more than the retail rate.

All scheduling coordinators (including the Cal PX before it ceased operations in January 2001) were required to submit a balanced schedule of load and generation to the Cal ISO for the following day. The Cal ISO then performed a security analysis to determine if the generation selected could serve customer demand without causing congestion on the transmission system. Although the rules were being modified constantly during 2000–2001, the basic steps of the day-ahead auction process were as follows:

- 7:00 a.m.—The Cal PX conducts 24 hourly energy auctions for the following day.
- 9:00 a.m.—The unconstrained market-clearing prices (i.e., a single price for all of the Cal ISO system) become publicly available.
- 10:00 a.m.—The Cal PX (like all scheduling coordinators) submits to the Cal ISO the estimated load for the next day and the generating resources that will produce the energy necessary to serve that load.
- 11:00 a.m.—The Cal ISO either determines that the initial schedule is feasible (no congestion) using the available transmission facilities or requires that the schedule be modified by redispatch using adjustment bids.
- 12:00 p.m.—Modified schedules are submitted. At this time, the Cal ISO can automatically modify schedules to relieve any remaining congestion.
- 1:00 p.m.—The Cal ISO calculates the day-ahead charge for congestion on any congested paths.
- 3:00 p.m.—The Cal PX publishes zonal price information when there is transmission congestion in the day-ahead market. The zonal price differences are equal to the Cal ISO's hour-ahead congestion charges along the relevant paths.

The Cal ISO operates a variety of markets in order to procure the resources necessary to reliably operate the transmission system, including a day-ahead market and an hour-ahead market for relieving transmission congestion and an energy market to continuously balance the system's energy needs in real time. The Cal ISO's real-time market is the final energy market to clear chronologically, after all other

markets in the region. Bilateral spot markets at trading hubs outside California generally operated in the time period between the close of the Cal PX market and the Cal ISO real-time market.

Understanding the interaction of the Cal PX and Cal ISO spot markets with all their complexities, together with the different market operations outside of California, is crucial to understanding and analyzing the impact of the various Enron trading strategies. An example of the market complexities in California market rules is the transmission congestion management system. A transmission path is "congested" when total schedules exceed the available transmission capacity of the facilities. The Cal ISO used a zone-based approach to alleviate congestion. Buyers and sellers submitted adjustment bids identifying the prices they were willing to use to increase or decrease their generation on demand to relieve congestion in a particular zone. However, the software used by the Cal ISO to evaluate adjustment bids did not accept prices that were higher than the Cal ISO price cap. These and other market rules not only caused market inefficiencies but also contributed to bidding strategies that circumvented the market design, such as underscheduling by the three California IOUs. This, in turn, created an opportunity for Enron to develop strategies that capitalized on the market rules and the trading behavior of others.

The Cal ISO's and Cal PX's MMIP Contains an Antigaming Provision and an Anomalous Market Behavior Provision

The MMIP is one of several protocols that (as explained below) the Commission required the Cal ISO and Cal PX to include as part of their filed rate schedules.[1] The underlying purposes of the MMIP are discussed in the Objectives section of the MMIP. In pertinent part, this section reads:

> This Protocol (MMIP) sets forth the workplan and, where applicable, the rules under which the ISO will monitor the ISO markets to identify abuses of market power, to ensure to the extent possible the efficient working of the ISO Markets immediately upon commencement of their operation, and to provide for their protection from abuses of market power in both the short term and the long term, and from other abuses that have the potential to undermine their effective functioning

[1]Both the Cal PX and Cal ISO have substantially similar MMIPs. For convenience sake, we will refer to the language of the Cal ISO's MMIP.

or overall efficiency in accordance with Section 16.3 of the ISO Tariff.[2]

In Staff's view, one key function of the MMIP is to put market participants on notice as to the "rules of the road" for them so that the markets operated by the Cal ISO are free from abusive conduct and can function as efficiently and competitively as possible. Thus, while one key function of the market surveillance unit (which is created by the MMIP) is reporting, "that function is designed to facilitate efficient corrective actions to be taken by the appropriate body or bodies [including this Commission] when required."[3]

In short, while the MMIP does not expressly prohibit any specific behavior, including the Enron trading strategies, Staff believes that market participants cannot reasonably argue that they were *not* on notice that misconduct that arose from abuses of market power and that adversely affected the efficient operations of the Cal ISO and Cal PX markets (as delineated in the MMIP) would be a violation of the Cal ISO or Cal PX tariffs. Staff believes that the key function of the MMIP is to put market participants on notice of what practices would be subject to monitoring and, potentially, corrective or enforcement action, by either the Cal ISO in the first instance or, as a last resort, by the Commission, whose function is to enforce the terms and conditions of filed rate schedules.

With respect to past actions of sellers (both public utilities and governmental entities) under either the Cal PX tariff or the Cal ISO tariff, however, the Commission's remedial authority may be broader. Staff believes that most of the misconduct engaged in by participants in the Cal ISO and Cal PX markets may come within the scope of the MMIP found in both tariffs.

As set forth in the Cal ISO's MMIP 1.3.1, the MMIP applies to "all ISO market participants; PX participants; [and] the ISO."[4] As set forth in the Cal PX's MMIP 1.3.1, the MMIP applies to Cal PX participants, market participants "whose actions have the potential to influence the competitiveness or the achievement of efficiency in the PX markets," and the Cal PX itself.[5]

Part 2 of the MMIP specifies what are termed "Practices Subject to Scrutiny." Among those practices are two of particular concern to the

[2]MMIP 1.1.
[3]MMIP 1.1.2 (Reporting Requirements).
[4]MMIP 1.3.1.
[5]MMIP 1.3.1.

Commission: "gaming" and "anomalous market behavior." Gaming is defined as:

> "Gaming," or taking unfair advantage of the rules and procedures set forth in the PX or ISO Tariffs, Protocols or Activity Rules, or of transmission constraints in periods in which exist substantial Congestion, to the detriment of the efficiency of, and of consumers in, the ISO [and PX] Markets. "Gaming" may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity, such as loop flow, facility outages, level of hydropower output or seasonal limits on energy imports from out-of-state, or actions or behaviors that may otherwise render the system and the ISO [and PX] Markets vulnerable to price manipulation to the detriment of their efficiency.[6]

Anomalous market behavior is defined as:

> Anomalous market behavior . . . is . . . behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or as behavior leading to unusual or unexplained market outcomes. Evidence of such behavior may be derived from a number of circumstances, including:
>
> - withholding of Generation capacity under circumstances in which it would normally be offered in a competitive market;
> - unexplained or unusual redeclarations of availability by Generators;
> - unusual trades or transactions;
> - pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, e.g., prices and bids that appear consistently excessive for or otherwise inconsistent with such conditions; and
> - unusual activity or circumstances relating to imports from or exports to other markets or exchanges.
>
> The [ISO] Market Surveillance Unit [or PX Compliance Unit] shall evaluate, on an ongoing basis, whether the continued or persistent presence of such circumstances indicates the presence of behavior that is designed to or has the potential to

[6]Cal ISO MMIP 2.1.3; Cal PX MMIP 2.1.4. Hereafter, for convenience sake, we will refer to the antigaming provision as MMIP 2.1.3.

> distort the operation and efficient functioning of a competitive market, *e.g.*, the strategic withholding and redeclaring of capacity, and whether it indicates the presence and exercise of market power or of other unacceptable practices.[7]

Section 2.3 of the MMIP and its several subparts address in detail how the Cal ISO, including the market surveillance unit, is to respond to determinations that market participants are engaged in any of the suspect practices delineated in the MMIP. While the MMIP outlines intermediate steps (such as arranging for alternative dispute resolution or proposing language changes to the tariff), ultimately it directs the market surveillance unit to refer matters to the Commission for enforcement.[8] In other words, the MMIP contemplates that, while the Cal ISO may try to correct misconduct on its own, the Commission is to be "the court of last resort" for misconduct committed by market participants, including the gaming and anomalous market behavior misconduct defined in the MMIP. Because of the fact that Part 2 of the MMIP specifically enumerates suspect practices, that Section 7.3 of the MMIP authorizes the Cal ISO to impose "sanctions and penalties" or to refer matters to the Commission for appropriate sanctions or penalties, and that the MMIP is part of the Cal PX's and Cal ISO's rate schedules on file with the Commission, Staff concludes that entities that transact through the Cal PX or Cal ISO and engage in such enumerated practices are in violation of those filed rate schedules.

The stated objectives of the MMIP are to identify abuses of market power by giving particular scrutiny to a list of abusive practices and misconduct and to take corrective action, including sanctions and penalties. In Staff's view, the identified misconduct remains a violation of the Cal ISO's and Cal PX's filed rate schedules even if such formal procedures as referral outlined in the MMIP did not occur. The Commission can enforce a rate schedule on file even when there are processes in that rate schedule which, had they been used, would have assisted the Commission. Ultimately, the Commission can enforce a tariff with or without the assistance of a complaint or referral.

The Cal ISO and Cal PX initially submitted the MMIP (along with other protocols) for informational purposes only on October 31, 1997. The Commission, however, found that the protocols, including the MMIP, "govern a wide range of matters which traditionally and typically appear in agreements that should be filed with and approved

[7] Cal ISO MMIP 2.1.1 (subparts MMIP 2.1.1.1 through 2.1.1.5 are denoted by bullets); Cal PX MMIP 2.1.1 (subparts a to e).
[8] MMIP 3.3.4.

by the Commission."[9] Therefore, the Commission accepted the protocols, including the MMIP, for filing, and directed the Cal ISO and Cal PX to post the protocols on their Internet sites and to file the complete protocols pursuant to Section 205 of the Federal Power Act within 60 days of the Cal ISO's operations date.[10] The Cal ISO and the Cal PX made their compliance filings on June 1, 1998. Accordingly, the MMIP has been part of the Cal ISO's filed rate schedule and the Cal PX's filed rate schedule since the Cal ISO's operations date (April 1, 1998).

Staff Finds That There May Have Been Numerous Instances of the Misconduct Addressed in the MMIP

Staff now reviews some of the various forms of misconduct discussed throughout this Report and provides its preliminary views on how the misconduct violated the MMIP. Staff recommends that the Commission issue orders to show cause to the companies specified in this chapter as to why the identified behaviors did not violate the Cal ISO or Cal PX tariff protocols and why unjust profits should not be remitted to customers.

Further, because these behaviors involve past violations of a filed rate schedule, such disgorgement of unjust profits would relate to periods prior to the October 2, 2000 refund effective date in the California Refund Proceeding and would be in addition to any refunds owed to customers in establishing just and reasonable rates for the period October 2, 2000 through June 21, 2001.

In the Commission's July 25, 2001 Order in the California Refund Proceeding,[11] the Commission discussed at length its establishment of the October 2, 2000 refund effective date. While rejecting a variety of arguments for refunds preceding that date, the Commission expressly noted that one exception to the refund limitations set forth in Section 206 was "where the sellers have charged a rate other than the filed rate."[12] The Commission explained:

> We agree that the Commission may take retroactive action to address circumstances where a seller did not charge the filed

[9] *Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,320 at 62,470-471 (1997).
[10] Id.
[11] *San Diego Gas & Electric Co., et al.*, 96 FERC ¶ 61,120 at 61,506-511, *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001).
[12] 96 FERC at 61,504.

> rate or violated statutory or regulatory requirements or rules in applicable rate tariffs.[13]

However, in the July 25 Order, the Commission stated that there had been no demonstration that there were any violations of any Commission-filed tariffs.[14]

The July 25 Order preceded the initiation of this investigation, and Staff finds that the Commission's statement that there were no tariff violations that would warrant refunds prior to October 2, 2000 appears to be no longer accurate. In short, Staff believes that numerous participants in the Cal ISO and Cal PX markets violated the terms of the Cal ISO's or Cal PX's tariff, specifically the MMIP; thus, the Commission could order disgorgement of unjust profits prior to October 2, 2000 if it determines there have been such violations.

The Enron Trading Strategies and Their Impact on Prices

As stated in our Initial Report, quantifying the exact economic impact of the trading strategies is difficult because we have not identified a way to definitively associate particular transactions with particular strategies. A passage from an undated Enron document entitled "Public Service of New Mexico California Service Overview" illustrates this point. The document describes a partnership arrangement providing mutual benefits and services, e.g., Enron acting as a scheduling coordinator on behalf of Public Service of New Mexico for certain trades. The document states that in Enron's opinion no Cal ISO forms or notifications are required: "in fact the ISO will not even be aware that PNM is in the path."

On January 6, 2003, the Cal ISO Department of Market Analysis released a 34-page report entitled "Analysis of Trading and Scheduling Strategies Described in Enron Memos" (January 6 Cal ISO Report), originally dated October 4, 2002. While the Cal ISO indicates that some of the results of its analysis require further verification, the analysis is generally consistent with our Initial Report as to the effect these strategies had on the market.

The Cal ISO's Department of Market Analysis issued a report on November 15, 2002 entitled "Did Any of Enron's Trading and

[13] Id at 61,507-80 (citing *Washington Water Power Co.*, 83 FERC ¶ 61,282 (1998), in which the Commission imposed sanctions and required public utilities to disgorge profits derived from past violations of the companies' market-based rate orders).
[14] Id.

Scheduling Tactics Contribute to Outages in California?" (November 15 Cal ISO Report). This report concludes that while Enron strategies could have financial impacts on the markets, they did not contribute to the outages during the winter of 2000–2001. Staff notes that the Cal ISO Report was submitted in a state proceeding before the California Select Committee to Investigate Price Manipulation of the Wholesale Energy Market (California Committee). The November 15 Cal ISO Report addresses and specifically refutes statements and allegations made by Mr. Robert McCullough in two earlier memoranda presented as part of his testimony before the state proceeding. In the memoranda he argues that the Enron strategies played a role in the blackouts during the winter of 2000–2001.

The Enron trading strategies clearly fall within the scope of the MMIP's antigaming and anomalous market behavior prohibitions. Indeed, one of the now infamous Enron memoranda that the Commission posted on the Web site for this proceeding even lists these prohibitions in a discussion of the trading strategies (however, the memorandum does not conclude whether or not the trading strategies are gaming or anomalous market behavior).

We will discuss the various trading strategies in the same order as in the Initial Report. We first focused on "load shift" because, by Enron's own admission, this was an explicit attempt to manipulate prices.

The second set of trading strategies discussed includes marketing power and energy in an effort to sell the product where it is needed the most. These strategies include various forms of exports and imports.

The last set of trading strategies involves deceitful tactics, such as providing false information or reporting imaginary transactions.

Price Manipulation—Load Shift

As described in the May 8, 2002 Data Request, the trading strategy known as load shift involves a company submitting an artificial load schedule in order to receive interzonal transmission congestion payments. Load shift involves deliberately creating congestion on a transmission line to increase the value of Enron's transmission rights and is clearly an attempt to manipulate prices. This Enron trading strategy is particularly complicated and its success was dependent, in part, on the independent bidding behavior of other entities.

By Enron's own admission, the load shift strategy was not very successful. Enron was not able to move the price paid for congestion

management. However, whether successful or not, it was a clear attempt to manipulate prices.

As described in the Enron memoranda, the load shift trading strategy involves creating the appearance of congestion by deliberately overscheduling in one zone (e.g., the southern zone) and underscheduling by a corresponding amount in another zone (e.g., the northern zone). For example, assume Enron's true load and resources were balanced by zone. Enron schedules an additional 100 MW of load in the southern zone and underschedules by the same 100 MW in the northern zone. This inaccurate schedule requires 100 MW of additional north-to-south transmission relative to Enron's true loads and resources. By shifting load in this manner, Enron created congestion and potentially raised congestion prices. This benefited Enron because it owned Firm Transmission Rights (FTRs) on the paths that it attempted to congest.

As stated in the Initial Report, Enron purchased 1,000 MW (62 percent) of the 1,621 MW in rights to north-to-south transmission on Path 26. The purchase of these FTRs cost Enron a total of $3.6 million. Path 26 is one of the two main transmission interfaces linking northern and southern California.[15] Enron's FTRs entitled it to collect a significant portion of all congestion revenues on Path 26 that were due to north-to-south congestion, the typical direction of congestion during periods of peak demand in the summer. This gave Enron an incentive to try to create—through a load shift—north-to-south congestion over this transmission line. If Enron could shift load and thereby increase the congestion price, it would be paid the higher price for all 1,000 MW of the FTRs.

The vast majority of Enron's congestion revenues were from Path 26 during July and August 2000, and totaled approximately $33 million for those 2 months for that path alone. This amount represented a considerable profit above the $3.6 million that Enron paid for the Path 26 FTRs, even though (as explained below) it was not able to manipulate the prices of congestion payments.

Enron was generally not able to move the cost of congestion because two large market participants, SoCal Edison and PG&E, often set the price for congestion relief over a large band of load used for congestion relief. Nonetheless, the false schedules that Enron

[15] It is useful to think of the California system as an hourglass figure, with the two transmission paths connecting the northern and southern zones. During the winter, these paths constrain lower-cost generation in the south from reaching load in the north. Conversely, during the summer, these paths constrain lower-cost generation in the north from reaching load in the south.

submitted added unneeded confusion to the already complex congestion management program that the Cal ISO administered. In this manner, Enron harmed the market. It is also important to not view the Enron trading strategies in isolation.

In an FTR Market Report dated December 1, 2000, the Cal ISO states that it actively monitored the FTR market and closely scrutinized Enron's scheduling behavior. The FTR Market Report noted that PG&E's underscheduling of load in the Cal PX day-ahead market could cause or exacerbate north-to-south congestion on Path 26. The Report concluded:

> It is important to note that the [Cal ISO's] examination of bidding behavior has revealed that the primary FTR owners on Path 26 were not the entities causing these congestion and load scheduling patterns. Rather, these patterns are the result of behavior by other load-serving entities. Thus the major FTR holders were the beneficiaries of usage charge revenues resulting from the cost minimizing bidding strategy of load-serving entities in northern California.[16]

While Enron's load shift trading strategy by and large did not move the price paid to relieve congestion, Enron nevertheless attempted to raise the price of congestion by artificially scheduling load in the hopes that it could collect higher revenues. This trading strategy was defeated, not by market rules or oversight, but rather by the actions of other companies (primarily PG&E in the north and SoCal Edison in the south) that were underscheduling load, contrary to the market design rules. Both of these behaviors would be prohibited by Staff's recommendation to prohibit submission of false information. Market rules should also be designed to economically discourage infeasible schedules.

Finally, we note that in Mr. McCullough's testimony before the California Committee, he references a letter from a former Enron employee named David Fabian to Senator Boxer. The letter refers to Enron's rights to north-to-south transmission on Path 26. According to Mr. McCullough's testimony, this person "heard" that Enron overbooked the line and that Enron "was allowed to price-gouge at will." Both Staff's analysis and the Cal ISO analysis of the economic impact of this Enron strategy indicate that this allegation is wrong. Additionally, this former Enron employee alleged that this overbooking strategy resulted in 2 days of rolling blackouts in northern California in the summer of 2000. Staff notes that this Enron scheme was designed to increase its congestion revenues. However, there is no

[16]FTR Market Report, p. 35.

evidence to suggest that any of the schemes or other practices discussed in the Enron memos contributed to the blackouts that occurred in California. As a general matter, congestion schemes such as this raise prices but do not factor into actual power flows.

Staff concludes that load shift falls within the definition of gaming because it involves taking unfair advantage of the Cal ISO's or Cal PX's tariffs or rules, "to the detriment of the efficiency of, and of consumers in, the ISO [or PX] Markets."[17] To the extent that load shift involves creating false congestion or the receipt of excess congestion revenues, it also involved "taking undue advantage of . . . transmission constraints in periods in which exist substantial Congestion."[18] Finally, since load shift is a prime example of price manipulation, it is also a behavior that makes the Cal PX or Cal ISO markets "vulnerable to price manipulation to the detriment of their efficiency."[19] In short, we conclude that all companies, including Enron, that engaged in load shift violated at least MMIP 2.1.3.

Price Maximization—Exports

The following two trading strategies involve using exports and imports in some way to sell power where or when it is most valued.

Export of California Power

The trading strategy known as "export of California power" involved buying energy at the Cal PX to export outside of California in order to take advantage of the price spread between the California market (which was capped) and the uncapped markets outside of California.

As noted in our Initial Report, fewer than a dozen entities either admitted to engaging in exports of California power or gave answers other than a denial. However, Staff notes that data indicate an increase in total exports from California during this period.

In narrative responses to the May 8 Data Request, various market participants argue that some of the Enron trading strategies, such as exports of California power, are examples of economically rational behavior, or legitimate arbitrage. They note that the Cal PX, Cal ISO, and the Commission have never implemented market rules prohibiting the export of energy from California. Respondents maintain that exporting power outside of California in order to reach other market opportunities, or to take advantage of a price spread, is good business

[17] MMIP 2.1.3.
[18] Id.
[19] Id.

practice. They argue that, from an individual entity's perspective, an export may have provided an optimal business opportunity.

For example, some respondents state that California generators may have wanted to make a long-term sale to avoid being entirely exposed to the California spot markets. Staff notes that, under California's restructuring plan, the three California public utilities were required to buy their energy in the spot market. This created an incentive for entities with in-state generation who desired to enter into forward sales to seek markets outside of California. Also, they simply may have exported spot sales to avoid the price cap in California.

While it may have been a rational economic decision for an individual company to export its power to a market with higher prices, the large amount of exports collectively contributed to the scarcity in California during 2000–2001. The Enron trading strategy called "thin man" (described as the opposite of the strategy called "fat boy") involved submitting a false schedule that artificially decreased load in California and an equal amount of energy exports. Moreover, if entities other than Enron acted in concert on a coordinated basis to implement this strategy, it would represent a form of cooperative corporate behavior with significant ramifications.

Historically, California has relied heavily on generation imports to meet its peak summer needs. However, the summer of 2000 did not follow this pattern. In fact, compared to earlier periods, the total amount of power exported from California during that summer was significantly larger than expected. This anomaly has been the subject of prior reports and studies. For example, a report by the General Accounting Office (GAO) on California restructuring indicated that monthly exports from May through October 2000 were between 40 and 230 percent higher than the same months in 1998 and 1999. Overall, exports were approximately 200 percent higher from May through October 2000 than in the same period in either 1998 or 1999.[20]

When California deregulated its retail electric market, the three California public utilities sold their oil- and gas-fired generation assets to other entities that did not have franchised service areas or an obligation to serve particular customers. At the time, this was a unique retail market structure in the West. The differences in retail market structures, including the mandated reliance on the spot market in California, contributed to the regional market problems. A merchant

[20]U.S. General Accounting Office, *Restructured Electricity Markets: California Market Design Enabled Exercise of Market Power*, Report No. GAO-02-828 (released July 2002), p. 32 (GAO California restructuring report).

generator who exported power out of California in search of a better price or the opportunity to sell in forward (rather than spot) markets was behaving in a rational economic manner. Existing, vertically integrated utilities in neighboring states still had an obligation to serve their native load from their own generation resources. When it was economical, these utilities also bought generation from California to serve their load or for resale in other Western markets, whichever was most valuable.

Staff concludes that the export trading strategy was largely the result of asymmetrical market rules under which products were sold where they brought the highest price.

Ricochet or Megawatt Laundering

The trading strategy known as "ricochet" or "megawatt laundering" involved one entity buying energy from the Cal PX in the day-ahead market and exporting it to a second entity, which received a fee from the first company. The energy was later sold to the Cal ISO in the real-time market (or as an out-of-market sale).[21]

Ricochets necessarily involve multiple entities, and the responses to Staff's data requests indicate that there was an abundance of willing counterparties. Because both generation and transmission were required, Enron needed others to move power into and out of the Cal ISO system. As noted in our Initial Report, most of the transmission facilities critical for these trading strategies that are directly connected to the Cal ISO system are owned or controlled by nonpublic utility California municipals, including the Transmission Agency of Northern California (TANC) and the City of Los Angeles Department of Water and Power (LADWP).

In addition to California transmission systems not operated by the Cal ISO, Enron also relied on transmission systems in the Pacific Northwest, specifically, those of Bonneville Power Administration (BPA), Avista, and Enron's public utility affiliate, Portland. Transcripts of Portland traders and transmission personnel include detailed instructions by Enron personnel on how the various participants (Portland and Avista) were to record transactions and how to report the various parts of the transactions consistent with NERC requirements and the Commission's regulations.

[21] If there were insufficient bids in the Cal ISO real-time market, the Cal ISO, as a last resort to procure the resources necessary to operate the system, would purchase energy out of its market. These out-of-market resources were paid their bid, but did not affect the market-clearing price paid to other generators.

Entities routinely try to capture profits from price differences that exist between different time periods, e.g., purchasing power in the day-ahead market and selling it in real time. The actual price in the real-time market can be higher or lower than the original price paid in the day-ahead market. Entities that engage in these strategies assume this arbitrage risk where others are unwilling to do so.

During the 2-year review period, this trading strategy could also be used to avoid the price caps that were set in the Cal ISO real-time market. This is because the Cal ISO also bought power out of market at the last minute when there was insufficient supply bid into its market. These out-of-market purchases were typically priced above the price cap. Suppliers knew that the Cal ISO would pay any price in an effort to avoid blackouts. In the Initial Report, Staff concluded that this behavior (raising prices at the last minute, when buyers are unable or incapable of saying no) was not legitimate arbitrage, but was an exercise of market power. We reaffirm this conclusion and view it as inappropriate gaming of the system.

Staff concludes that the ricochet trading strategy, at a minimum, is an example of anomalous market behavior—that is, "behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or behavior leading to unusual or unexplained market outcomes."[22] Indeed, the MMIP includes as one of the examples of anomalous market behavior "unusual activity or circumstances relating to imports from or export to other markets or exchanges."[23] In short, Staff concludes that all entities that engaged in the ricochet trading strategy violated at least MMIP 2.1.1.5.

The Enron memoranda indicate that Enron included the generation of other sellers, such as British Columbia Power Exchange (Powerex) and Puget Sound Energy, Inc. (Puget), when employing this trading strategy. In addition, Cal ISO data indicate that during the critical period of the first week in December 2000, 10 market participants may have engaged in this trading strategy and may have generated close to $10 million in profits. The 10 market participants are listed in descending order of potential profits:[24]

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[22]MMIP 2.1.1.

[23]MMIP 2.1.1.5.

[24]These transactions represent exports and imports by the same entity; therefore, the screen used by the Cal ISO is very conservative because it does not include transactions in which the import and export legs were performed by two or more parties. (See Issue 3 Chart in Cal ISO's Response to Staff's February 10, 2003 Data Request.)

- Puget Sound Energy
- Powerex or British Columbia
- Avista Energy Inc.
- Los Angeles Department of Water and Power
- PacifiCorp
- Enron Energy Services, Inc.
- Portland General Electric
- Bonneville Power Administration
- Arizona Public Service Corporation
- Idaho Power Company (also referred to as Ida Corp.)

Staff concludes that, to the extent these 10 market participants used exports from California prior to real time in order to withhold generation until the last minute for sales to the Cal ISO, such activity is an exercise of market power and a violation of the Cal ISO tariff.

Staff recommends that the potential ricochet transactions of the 10 entities listed in this section be part of the show cause order discussed later in this section.

Trading Strategies Based on False Information

The following trading strategies are all premised on submitting false information schedules. One trading strategy, fat boy, was designed to offset the bidding strategies of the California public utilities. In addition, this strategy itself did not affect market outcomes. The other trading strategies are all attempts to fabricate transactions for profit and to change market outcomes.

After the Staff Initial Report was released, Jeffrey Richter, an employee of Enron and the manager of the Short-Term California trading desk in 2000, pleaded guilty to several counts. The February 3, 2003 Plea Agreement states that he and other individuals at Enron agreed to devise and implement fraudulent schemes through the California spot markets. In this regard, the schemes required them to submit false information to the Cal ISO in the electricity and ancillary services markets. The Plea Agreement states the following:

> Among other things, we knowingly and intentionally filed energy schedules and bids that misrepresented the amount and geographic location of the load we intended to serve. We

did so for the purpose of increasing the appearance of congestion on transmission lines, increasing the market price for congestion fees for transmission between zones, earning congestion payments that otherwise would not have been available, and increasing the values of our FTRs (which only generated revenue when congestion existed).

We also submitted bids to supply ancillary services that we did not have, or did not intend to supply, in the ISO's day-ahead ancillary services market. The bids we submitted contained fabricated information regarding the source and nature of the ancillary services we proposed to supply to the ISO. Once the bids were accepted, we would cancel our obligation to supply the ancillary services by purchasing them in the ISO's hour-ahead ancillary services market. Enron would then profit by capturing the difference in price between the two markets.

Fat Boy (or Inc-ing Load)

The fat boy trading strategy involved a scheduling coordinator, such as Enron, artificially increasing ("inc-ing") load on the schedule it submits to the Cal ISO to correspond with the amount of generation in its schedule.[25] Under California market rules, all schedules submitted to the Cal ISO had to be balanced (i.e., load and generation had to be equal). The company then dispatched the generation it scheduled, which was in excess of its actual load. This resulted in the Cal ISO paying the company for the excess generation at the clearing price established in the real-time market.[26]

Staff emphasizes that this trading strategy was conceived and used in response to the procurement strategy used by the three California public utilities, which itself was a response to the unintentional interplay of Cal PX and Cal ISO market rules. The Cal PX, as the scheduling coordinator for the three California public utilities, was required to send the Cal ISO a schedule that balanced an equal amount of generation and load. The Cal PX day-ahead market cleared before the Cal ISO market, which was capped at various levels (depending on the date). Under the original California restructuring program, PG&E and the two other California public utilities were supposed to "bid all

[25] An Enron strategy with the opposite market effect was called thin man, in which a load is artificially reduced and a corresponding amount of generation is exported out of California.

[26] Staff performed an electronic search of the Enron transaction database (Enpower) with an explicit reference to "fat boy." This search produced approximately 100 transactions predominantly in coordination with the Cities of Glendale and Redding, California and Valley Electric.

of their generation into the Power Exchange and satisfy their need for electric energy on behalf of their full service customers with purchase made from the Exchange" (D.95-12-063). California required this buy-sell procedure in order to: (1) provide price transparency, (2) mitigate market power and reduce the burden of regulatory issues, (3) ensure that customers would receive the benefit of competitive market prices, and (4) provide sufficient depth to the PX such that its market signals could be relied on as a benchmark.

In an effort to minimize their procurement costs under the California market rules, the three California public utilities, especially PG&E, habitually underscheduled their load in the Cal PX market. In other words, they would only buy energy in the Cal PX market that was priced at or below the capped Cal ISO real-time market, relying on the fact that residual load could be supplied in the Cal ISO real-time market at capped prices. PG&E's strategy involved a deliberate attempt to push the Cal PX price below the capped price in the Cal ISO real-time market.[27]

PG&E's load makes up a significant portion of the load in California. Its load represents approximately 85 percent of the demand in northern California, the NP15 zone. Therefore, PG&E's decisions on how to bid its demand have a significant impact on both buyers and sellers in the market. Due to PG&E's large size, changes in the company's bidding behavior that represented a shift from the market design not only caused uncertainty and volatility but also greatly influenced a number of market outcomes, including market-clearing prices. The most obvious problem was shifting a large percentage of its load out of the Cal PX day-ahead market, causing the load to be met with the Cal ISO's real-time market, resulting in increased reliability problems.

Bid data submitted by PG&E to the Cal PX on August 26, 2000 demonstrated its bidding strategy. PG&E's expected load between 12:00 and 1:00 p.m. was 9,060 MW. PG&E's bid indicated that it was only willing to purchase its total expected load if the price was less than or equal to $75/MW in that hour. As the Cal PX price increased, PG&E was willing to purchase decreasing amounts. For example, if the expected price rose to $200/MW, PG&E was only willing to purchase half of its total expected load (4,530 MW). Because the actual clearing price in NP15 that hour was $249.39/MW, PG&E actually purchased 3,813 MW in the Cal PX. As a result, the

[27] As initially proposed in the November 1, 2000 Order and as adopted in the December 15 Order, the Commission halted the practice of near-total reliance on the spot market to allow the three California public utilities to procure a more balanced portfolio and to procure resources under long-term contracts.

remainder of PG&E's load (5,242 MW) would have to be served by purchases in the Cal ISO's real-time market. Due to this bidding strategy, an equal amount of supply was not committed in the Cal PX day-ahead market.

The obvious short-term effect of PG&E's bidding strategy was to reduce the amount of load in the Cal PX day-ahead market, which reduced the price for every megawatt purchased in that market. However, this bidding strategy had the opposite effect on the Cal ISO real-time market. By increasing the amount of load served by the Cal ISO's real-time market, the price for every megawatt served increased. Due to PG&E's large size, its actions caused the market prices to move up and down appreciably.

Another disruptive market outcome caused by PG&E's bidding strategy occurred in December 2000. During this period, other market participants were willing to pay more for energy in the Cal PX market, which resulted in PG&E's transition from a net buyer of generation (including its own resources bid into the market) to a net seller. In other words, PG&E's bidding strategy resulted in the loss of its own generation to buyers, including out-of-state entities. This, of course, resulted in an even greater amount of PG&E load relying on service from the Cal ISO in real time. According to PG&E, after it began losing its own generation to other buyers, it sought California Public Utilities Commission (CPUC) support to use an alternative bidding approach to keep its own low-cost generation for its retail customers. Even after discussions with CPUC President Lynch's office and the head of the Energy Division, it did not receive support to use the alternative bidding approach. Furthermore, the Cal ISO raised new reliability concerns.[28] Only after the FERC lifted the requirement that utilities sell their generation into the Cal PX market on December 15, 2000 was PG&E able to keep all of its own generation and contracts to meet its customers' demand.

While this procurement strategy attempted to minimize the public utilities' wholesale electricity costs, underscheduling caused chronic operational and reliability problems for the Cal ISO (as documented in numerous filings with the Commission). The Cal ISO's real-time market was designed to supply only the small amount of energy (less than 5 percent) needed to constantly balance generation with actual load. Chronic underscheduling in the Cal PX day-ahead market transformed this "balancing" market into an energy commodity market that served far more load than it was designed to supply. The uncertainty of not knowing how to supply a much larger percentage of

[28]PG&E e-mail dated January 30, 2001 (p. 0221) of their response to Staff's data request.

the load until real time caused considerable reliability problems for the Cal ISO. In short, California load-serving entities were using the real-time market for a purpose for which it was not intended.

Shifting load out of the day-ahead market into the real-time market put additional market pressure on the Cal ISO. When insufficient supplies were available in the Cal ISO real-time market, the Cal ISO was forced to procure necessary supplies through out-of-market purchases that were not subject to a price cap. The uncertainty of this last-ditch effort to procure necessary resources was significant. In addition, the end result was that energy prices in real time were often much higher than the Cal PX clearing price. The effect of both the higher Cal ISO clearing prices and the still higher out-of-market prices was felt by all load-serving entities until December 8, 2000, when the Commission issued its Order Accepting Tariff Amendment on an Emergency Basis. On that date, the Cal ISO made an emergency filing to amend its tariff in an effort to curb the underscheduling problem and to protect the reliability of the system. After this order, only entities that underscheduled or caused the imbalance were directly assigned the costs of out-of-market purchases.

In its filing, the Cal ISO stated that it had been forced to declare Stage 2 Emergencies for the previous 4 days, and saw no immediate relief. The Cal ISO requested three tariff modifications as follows: (1) increase the amount of generation in the real-time market by allowing bids above the then-current $250 cap (such bids would not set the market-clearing price); (2) assess penalties (twice the highest price paid by the Cal ISO) against generators that refused to operate in response to a Cal ISO dispatch instruction and, if firm load was curtailed, an additional penalty of $1,000/MWh for energy a generator failed to deliver; and (3) underscheduling entities such as PG&E would be allocated the highest priced energy and out-of-market purchases. Given the extraordinary circumstances, the urgency of the request, and the overriding reliability concerns, Commission acted immediately to accept the Cal ISO's proposed tariff changes.

The fat boy trading strategy was a response to this underscheduling problem. Under California market rules, all scheduling coordinators (e.g., Cal PX and others, such as Enron) were required to submit to the Cal ISO day-ahead schedules that were balanced. The fat boy trading strategy was a way to preschedule on a day-ahead basis an imbalance sale in the Cal ISO's real-time market. While neither underscheduling nor inc-ing load was an intentional part of California restructuring, it is clear to Staff that underscheduling was of far greater concern to the Cal ISO, no doubt because it led directly to reliability problems. Indeed, some of the respondents informed Staff that the Cal ISO

actually helped them to engage in the fat boy trading strategy by providing them with artificial or simulated load and delivery points. For example, an entity with only generation and no load could not submit a balanced schedule to the Cal ISO. According to Reliant, the Cal ISO created an artificial load point that enabled Reliant to submit a balanced schedule to the Cal ISO.

Enron's use of the fat boy trading strategy did not set the market-clearing price in the Cal ISO's real-time market. Under California market rules, entities are price takers for the amount of generation in excess of actual load; that is, they are paid the clearing price that is established in the Cal ISO market.[29] Nevertheless, the submission of false schedules, and the Cal ISO's encouragement of such fabrications to circumvent the balanced schedule rule, would be prohibited under Staff's recommendations in the Initial Report. The Initial Report included a recommendation that all tariffs for market-based rates include an express prohibition against submitting false information. In addition, all open access transmission tariffs should be amended to include this prohibition. Flawed market rules that are not working as intended should be amended by the Commission, not circumvented by market participants. More significant was the elimination of the market rule that held the three California public utilities in the spot market. As stated in the Initial Report, allowing a greater use of forward contracting resulted in far less reliance on the spot market, thus reducing the economic incentive for this trading strategy.

While Staff has concluded that the fat boy trading strategy alone did not set the market-clearing price in the Cal ISO's real-time market, and may in fact have been encouraged by at least one Cal ISO employee, this trading strategy nonetheless involves the deliberate submission of false information and falls within the scope of the antigaming provision because it necessarily involves taking "unfair advantage" of the Cal ISO's rules and may otherwise have made the "ISO Markets vulnerable to price manipulation to the detriment of their efficiency."[30]

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[29]The day-ahead and real-time imbalance pricing during May 20-23, 2000 illustrates this trading strategy. Unexpected high loads occurred on May 20-21, which caused prices in the Cal ISO real-time market to reach the $750 price cap while the Cal PX day-ahead prices were in the $40 to $50 range. Reacting to these prices, Enron and British Columbia Power Exchange Corporation overscheduled between 1,000 and 2,000 MW of generation as "price takers" in the Cal ISO real-time market on May 22. Because the Cal ISO market continued to exceed the Cal PX day-ahead prices, the fat boy strategy was profitable relative to selling in the Cal PX. On May 23, 2000, these two scheduling coordinators continued to overschedule more than 1,000 MW in the Cal ISO imbalance market. However, the Cal ISO's market dropped to the $200 range, while prices in the Cal PX rose to the $300 to $500 range. Thus, this overscheduling strategy ceased, for a time, to be profitable relative to selling in the Cal PX.

[30]MMIP 2.1.3.

Underscheduling by the Three California Public Utilities

California public utilities submitted false schedules when they knowingly underscheduled their loads to the Cal PX. Their underscheduling violated the California restructuring plan and the antigaming provisions of the Cal ISO and Cal PX tariffs. Both of these conclusions are true irrespective of the fact that the California public utilities viewed this practice as a cost minimization strategy. While the Commission has the authority to order disgorgement of profits, there are no profits to disgorge from a price-reducing strategy.

Cal ISO Actions

Staff is also concerned that a review of certain Cal ISO reports indicates a complacency with the submission of false schedules, such as in the fat boy trading strategy. The Cal ISO issued a report by its Department of Market Analysis entitled, "Did Any of Enron's Trading and Scheduling Practices Contribute to Outages in California?" This report, which was reviewed by the Market Surveillance Committee, addressed issues raised by Robert McCullough before the California Committee. The report concludes that, based on data available to the Cal ISO, the Enron practices reviewed by Mr. McCullough did not cause the blackouts during the winter of 2001. Rather, the blackouts were caused by a combination of the limited supply of energy that was made available to the Cal ISO and limited transmission capacity available to deliver energy from southern to northern California.

Within this context, an addendum to the report discusses the fat boy trading strategy. Again, the Cal ISO report criticizes Mr. McCullough's previous analysis, but in doing so, the Cal ISO appears to view this strategy as benign or even helpful because it "simply has the effect of reducing the Cal ISO's projected demand for imbalance energy that must be procured by the Cal ISO to meet real time load." The Cal ISO also describes how, in performing its daily operations (such as system load projections and reserve requirements), it ignored the false information contained in the schedules submitted by Enron and others. The report seems to indicate that the Cal ISO was aware of the false underscheduling by the California public utilities and the counterbalancing effects of the false overscheduling of load by Enron and others.

Because the Cal ISO is the control area operator of the transmission grid, it is imperative that the Cal ISO identify poorly designed market rules and make filings with the Commission proposing solutions. However, the Cal ISO must implement the Commission-approved

rules until they are changed, as all other public utilities are required to do.

Transmission Congestion Strategies

Non-Firm Exports, Death Star, and Wheel-Out

In this section, we examine three Enron trading strategies known as "non-firm exports," "death star," and "wheel-out," along with similar variations.[31] All are designed to generate payments for relieving transmission congestion by "fooling" the Cal ISO's computerized congestion management program. These trading strategies generally involved scheduling transmission in the opposite direction of congestion, and thereby getting paid for the counterflow. They are all premised on imaginary transactions that are nonetheless eligible for congestion payments from the Cal ISO.

As described in the May 8, 2002 Data Request, in death star a company schedules energy in the opposite direction of congestion (counterflow), but no energy is actually put onto the grid or taken off of the grid. This trading strategy has been the subject of hearings in California. In a wheel-out, a company, knowing that an intertie is completely constrained (that is, its available capacity is set as zero) or out of service, schedules a transmission flow over the facility, knowing that the schedule will be cut and that it will receive a congestion payment without actually sending energy over the facility. In a non-firm export, a company gets a counterflow congestion payment from the Cal ISO by scheduling non-firm energy from a point in California to a control area outside of California and cutting the non-firm energy after it receives such payment.

As discussed in the Initial Report, the first instance of these trading strategies occurred on May 25, 1999. On that day, Enron scheduled an infeasible transaction in the Cal PX market across an intertie between southern California and Nevada. Because this schedule called for 2,900 MW to go across a line with only 15 MW of available capacity, it triggered the Cal ISO's congestion management procedures. A later investigation into this incident by the Cal PX resulted in a cash settlement by Enron.

[31] Related schemes that are referenced in documents other than the Enron memoranda include "black widow," "red congo," and the "Forney perpetual loop."

However, according to the Enron memoranda, these trading strategies became more complex and included the participation of other entities. The counterparties were used primarily to schedule parts of the transactions or to use transmission facilities outside the Cal ISO's control area in order to hide the transaction.

In fact, no energy flowed because the schedule began and ended at the same location. Noninvestor-owned California utilities, such as the Northern California Power Agency and LADWP, were also particularly crucial to these strategies because they own and control transmission facilities that interconnect with the Cal ISO's system but are outside the control of the Cal ISO, which was crucial in helping to avoid detection.

Staff notes that in its response to the May 8, 2002 Data Request, Powerex states that there is a structural flaw in the Cal ISO's congestion management software that prevents the software from recognizing that a tie is out of service. Powerex claims that it has a standing practice of maintaining adjustment bids at interties to relieve congestion. The Cal ISO occasionally requested Powerex to remove its adjustment bids when the Cal ISO intended to take the line out of service. However, if the Cal ISO did not provide such advance notice, Powerex would receive a congestion payment. Powerex states that it is unable to identify such payments.

In a March 15, 2001 e-mail from an Enron employee to the Enron Portland shift, he describes a new strategy for taking power from southern California to northern California using the Silverpeak intertie with the Sierra Pacific Power Company system as part of the transmission path. There is no indication from this e-mail that Sierra Pacific is aware of the import/export strategy. However, the following quote from the e-mail is interesting:

> Also do not sell to a marketer (especially POWEREX) without sleeving. We do not want anybody else to know about the path. If Powerex sees this I guarantee that they would try to schedule this and we do not want competition.

The Cal ISO report identifies Powerex, along with Coral Power, LLC (Coral) and Sempra Energy Trading Corporation (Sempra), as the largest recipients of revenues from this type of activity.

In addition, TransAlta described several transactions that have certain operational elements common to these Enron trading strategies. Unlike the Enron trading strategies, however, the TransAlta transactions actually moved power. For example, what TransAlta calls

"recirculation" was a way to move energy supply from southern California to northern California when the Cal ISO-controlled transmission path between these regions was fully subscribed. TransAlta would move the energy to the northwest using its transmission rights over non-Cal ISO facilities and then import the power into northern California. At times, the Cal ISO actively sought the assistance of TransAlta in implementing these energy transfers.

TransAlta was very helpful and aided Staff's understanding of different variations of the strategies by volunteering a significant amount of information. While TransAlta used a very broad reading of Staff's data requests and was very cooperative, many respondents took the opposite approach. In fact, some entities used such a narrow interpretation of the questions about the Enron strategies that, if Enron were to use these interpretations, it would not admit to using its own strategies.

An example is Sempra. Sempra denied engaging in the Enron strategies in its original May 22, 2002 response. On October 4, 2002, the Cal ISO issued a report prepared by the Department of Market Analysis, "Analysis of Trading and Scheduling Strategies Described in Enron Memos." This report was provided to regulatory and law enforcement agencies on a confidential basis. On January 6, 2003, the Cal ISO released the report publicly and posted it on its Web site. The report was intended to (1) indicate how extensively the Enron trading strategies may have been used by Enron and others and (2) identify specific schedules and transactions that could be further investigated. The report identifies Sempra in connection with its analysis of the following Enron trading strategies: wheel-out, scheduling energy to collect congestion charges, death star, and get shorty. The analysis indicates that Sempra was among the top three in all these categories and potentially generated more revenues than Enron in each strategy.

In a letter dated January 15, 2003, Sempra informed Staff that nothing in the Cal ISO report suggests that Sempra engaged in the Enron strategies. The Sempra explanation of how they could not have engaged in wheel-out illustrates our point.

The Enron memos describe wheel-out as a simple strategy that took advantage of a market design flaw. Knowing that an intertie is completely constrained or out of service, a company schedules a transmission flow over the facility. This strategy generates revenue because the schedule will be cut and it will receive a congestion payment without actually having to send energy over the facility. The Cal ISO report focused on revenues on out-of-service tie points only. In its defense, Sempra states that while it did submit schedules over a

facility even after it received notification of constraints on a facility, the Cal ISO notices are only for "informational purposes" and their accuracy cannot be relied on. Next, Sempra explains that it would only receive a payment if the Cal ISO actually cut its schedule. However, a payment can and should be expected when a line is out of service, which is all that the Cal ISO report focused on. Sempra concludes by stating:

> Thus, that [Sempra] may have received certain counterflow payments in connection with schedules or adjustment bids on tie points that were out of service, in no way suggests that [Sempra] submitted those schedules or bids *knowing* that the schedule would be cut and that it would receive a congestion payment without actually having to send energy over the facility.

Sempra wants Staff to believe that it ignored the fact that a facility was out of service, scheduled power over that facility anyway, and was shocked that it actually made money. Using this rationalization, not even Enron could be accused of engaging in the wheel-out trading strategy.

This lack of cooperation is not limited to jurisdictional public utilities. For example, the city of Glendale, California (Glendale) also denied any knowledge of the Enron strategies in its May 31, 2002 response to Staff's data request. On January 16, 2003, Glendale submitted a supplemental response maintaining that Glendale did not knowingly engage in the Enron trading strategies. However, included in the submittal are two memos (one from Enron and one from Coral) that were found during an internal review; these memos describe many of the Enron trading strategies in detail. They also describe the steps Glendale needs to take to implement the strategies in conjunction with Enron.

Under the heading "Phantom Ancillary Services," the Coral memo details how Glendale can bid capacity for day-ahead ancillary services when the capacity is not actually available. The memo describes Glendale's ability to use its non-Cal ISO transmission rights to "play" the Cal ISO system. Another strategy is called "detrimental price plays in ISO." Because both Glendale and Coral have load within California, this strategy involves phantom trades between the two in order to capture differences in energy prices between zones and congestion payments.

Glendale's continued denial of any knowledge of the Enron trading strategies is not supported by the evidence it submitted or the evidence

in the Enron e-mails described elsewhere in this chapter. For example, an Enron e-mail dated February 17, 2000, from an Enron employee to the Enron Portland shift, states the following:

> GLENDALE—we have been getting few opportunities to do profit sharing transactions with certain members of their staff. We need to let [Enron employee name] and myself know when we call to get them involved and they have no interest. Their manager wants to do this every time we see fit. Everyone needs to know why they don't want to play.

The city of Redding, California (Redding) is also discussed in the Enron e-mails as participating in the congestion relief scheme known as "red congo." In one e-mail to the Enron Portland shift, it is advised that red congo is a new marketing arrangement to relieve congestion that also uses Pacificorp West as the northwest utility that moves energy from south to north from the Cal ISO. Part of the scheme uses Redding's existing rights on non-Cal ISO transmission and a series of sales and purchases between the parties. This e-mail also notes the following: "Redding is on board with this strategy as is Pacificorp."

This preponderance of evidence suggests that nonjurisdictional entities such as Redding and Glendale were associated with Enron in executing the trading strategies in a willful and knowing manner.

These trading strategies would not be possible if a single comprehensive congestion management system were implemented in the West, as Staff recommends. In addition, artificial congestion or congestion relief would violate Staff's recommended tariff language prohibiting false schedules and information.

Staff concludes that the transmission congestion strategies not only involve gaming, but also may fall into the category of anomalous market behavior because they are departures from normal behavior in competitive markets and lead to unusual or unexplained market outcomes.[32] Staff emphasizes that Enron, in conjunction with other parties, took intentional advantage of the market rules in creating and implementing these trading strategies. The Cal ISO Report, as discussed earlier, identifies Powerex, Coral, and Sempra as the largest recipients of revenues for such strategies.

[32]MMIP 2.1.1.

Ancillary Services Strategies

Get Shorty

As described in the May 8, 2002 Data Request, the "get shorty" trading strategy involves the "paper trading" of ancillary services. Ancillary services include various types of generation capacity that are held in reserve for use in a contingency situation, such as the loss of a critical generation or transmission facility (e.g., replacement reserves). These services are required by the Cal ISO in order to reliably operate its system and to meet various operational standards.

In this trading strategy, Enron would commit to provide the ancillary services in the Cal PX's day-ahead market and then cover its position by purchasing those services in the Cal ISO's hour-ahead market. There is a legitimate profit motive here: to sell high in the day-ahead market and buy back at a lower price in the real-time market. Staff notes that Cal ISO Tariff Amendment No. 4, which the Commission accepted for filing,[33] permits the buyback of ancillary services as a legitimate form of arbitrage.

At one point a Cal ISO employee attempted to stop the buyback by setting a high market-clearing price. In this incident, which was examined by the California Committee, a former Cal ISO employee attempted to stop market participants from buying back ancillary services in the hour-ahead market at a low price. Transcripts from a recorded phone conversation indicate that the Cal ISO employee contacted an Enron trader and suggested that he submit a bid of $91.86 in order to set the market-clearing price at the then-current ceiling price. Following the conversation, the Enron trader did submit a bid at the maximum rate. The incident appears to be an isolated case.

The original Enron memoranda indicate that its traders committed to sell ancillary services without actually having the ancillary services on standby (which is why the trading strategy is also called paper trading). Because entities are required to identify the source of the ancillary services (that is, the specific generating unit), Enron's traders submitted false information to the Cal ISO. It is this aspect of the trading strategy—the deliberate submission of false information to the Cal ISO—that distinguishes it from permissible arbitrage activity. An e-mail dated January 11, 2000 from an Enron employee to the Enron Portland shift explains how Enron will take a more aggressive strategy

[33]California Independent System Operator Corporation, 82 FERC ¶ 61,327 (1998).

(currently used with Glendale) to bid into the day-ahead ancillary services market without the necessary re ces (i.e., paper trading of ancillary services).

The Initial Report concluded that, to the extent that this trading strategy involves deliberately supplying false information, the practice should also be prohibited.

The Cal ISO analysis reporting on this trading strategy notes the difficulty of determining whether resources were actually available when ancillary services were sold in the day-ahead market, especially when the resource is imported from another control area into the Cal ISO's control area. In an attempt to quantify the potential extent of this practice, the Cal ISO summarized the total amount of ancillary services sold back to the Cal ISO in the hour-ahead market. These data indicated that four entities were far more active than Enron, which had net sales of $5 million. These entities, in order of magnitude, are Coral Power, LLC ($17.1 million), Sempra Energy Trading Corporation ($13 million), Avista Energy Inc. ($11.8 million), and Modesto Irrigation District ($10.3 million). These four entities and Enron had a total net gain of more than $57 million.

As discussed in the final section of this chapter, these entities may not have acted independently. In fact, evidence recently produced by Enron in response to Staff data requests indicates that the buyback of ancillary services by certain entities may have been coordinated under the direction of Enron under business alliances. For example, in an Enron document entitled "Washington Water and Power (now Avista) Ancillary Services Information," the pricing arrangement states the following: "All Capacity revenue will be divided between WWP and [ENRON] in the following ratio: 75 percent to Washington Water and Power and 25 percent to Enron Power Marketing Inc." Following a similar description for splitting energy revenue, the document states that: "WWP understands this concept and prices accordingly."

An Enron e-mail dated June 5, 2000 describes the results of the joint effort and details "a summary of money made on ancillary services for the month of May" as follows:

Customer	Total Amount	Enron Amount
Colorado River Commission	$401,770	$220,885
City of Glendale	608,520	$150,135
Valley Electric Association	$56,038	$14,010
El Paso Electric Company	$2,000	$500
TOTAL	$1,068328	$385,530

Another e-mail dated November 5, 1999 to the Portland shift (with the subject line "DEAL ENTRY ERRORS") explains the consequences of such mistakes from both management's and the customer's perspective. For example, the e-mail states: "This morning our book showed us losing $51,000 because the Redding profit sharing deal was incorrectly entered...." Another customer complaint is explained as follows: "We have had to explain to EPE why they received only expost for their exercised ancillary services deal (it's because we had a zero exercise price in the hour ahead bid to the Cal ISO)." In the final section of this chapter, Staff makes further recommendations for further investigations of these and similar relationships.

Finally, Staff notes that this trading strategy was used more widely by other entities than indicated by the responses to our data request. Certain entities, through a very narrow reading of the question, were not forthcoming in their responses. Sempra's response is one example.

As explained in the Enron memo, the paper trading strategy involves the following: (1) a sale of ancillary services in the day-ahead market and (2) the next day, in the real-time market, the company "zeroes out" the ancillary services by canceling the commitment to sell and buying ancillary services in the real-time market to cover its position. The critical element here is that companies could commit to sell on a day-ahead basis without having capacity available and fulfill their obligation by buying this service from the Cal ISO in the hour-ahead (real-time) market.

The Sempra original response states: "[Sempra] did not sell ancillary services in the day-ahead market and later cancel its commitment to do so in the real-time market." It adds that there is nothing in the Cal ISO report and contradicts this statement because the clause "canceling commitments in the real-time market" is not mentioned. Sempra also argues that the Enron memo and Staff data request incorrectly refer to a buyback in the real-time market (rather than the hour-ahead market); therefore, it correctly denied engaging in the strategy.

In spite of this denial, Sempra has stated that it adjusted its ancillary service schedules in the hour-ahead market based on, among other things, market opportunities. However, this does not address the real question: was this revenue earned by legitimate arbitrage or through submitting a false schedule (i.e., committing capacity it did not have on a day-ahead basis). Once again, using Sempra's reading of the data request, not even Enron could be accused of engaging in the trading strategy. Staff notes that the preliminary screen used in the Cal ISO report shows that Sempra earned over $13 million, which is more than

twice the amount that Enron earned ($5 million). Staff notes that, according to the Cal ISO report, Coral Power, LLC, Avista Energy Inc., and Modesto Irrigation District of California also earned more than Enron.

Staff concludes that the get shorty trading strategy falls within the scope of the antigaming provision because it makes the Cal ISO or Cal PX markets vulnerable to price manipulation.[34] According to the Cal ISO report discussed in this chapter, Coral Power, Sempra, Avista Energy, and Modesto Irrigation District of Northern California, as well as Enron, had a total net gain of more than $57 million from the get shorty trading strategy.

Selling Non-Firm Energy as Firm Energy

As described in the Initial Report, in this trading strategy a company deliberately sells or resells what is actually non-firm energy to the Cal PX, while claiming that it is firm energy.

NERC prohibits this practice since it violates NERC's existing interchange rules. However, the Enron memoranda attempt to justify this trading strategy on the grounds that it supposedly brought additional supply to California with no apparent impact on Cal PX energy prices. The Enron memoranda also explain that Enron was subject to financial risk because, if the non-firm energy supply were cut, Enron would have to cover its position by purchasing that energy in the Cal ISO's real-time market as a price taker.

Staff finds this rationalization to be particularly troubling because Enron attempted to legitimize deception, the deliberate submission of false information, and actions that NERC expressly prohibited. This is a key example of why Staff is recommending an explicit prohibition against providing false information.

This trading strategy also compromises reliability because non-firm energy improperly represented to be firm energy is not backed up with reserve generation by the supplying party. This problem is made worse when non-firm energy is imported into another control area. The receiving control area will not procure reserves for the import under the illusion that the supplying party is responsible for providing adequate generation reserves. Because this Enron trading strategy usually involved a purchase, it is difficult to detect absent the reporting of the entity selling the non-firm energy to Enron.

[34]MMIP 2.1.3.

Recommended Commission Responses

The Enron trading strategies that were based on false information and that had an adverse effect on the markets are encompassed within the MMIP protocol of the Cal ISO and Cal PX tariffs. Therefore, Staff recommends that the Commission initiate show cause proceedings for the companies listed in this chapter, with disgorgement of unjust profits associated with the various transmission congestion strategies (e.g., non-firm exports, death star, and wheel-out), load shift, ancillary service sales without the necessary resources, megawatt laundering, and selling non-firm energy as firm energy. These proceedings should involve both public and nonpublic utilities that engaged in these strategies under the Cal ISO and Cal PX tariffs.

We emphasize that the trading strategies—while bearing Enron's name—were not limited to Enron but appear to have been widely engaged in by numerous parties. Indeed, it would appear to Staff that the majority of public utility entities, and some nonpublic utilities, engaged in at least some of the trading strategies some time during the 2-year review period. The cumulative effect of this prevalent alleged misconduct is that customers did not pay just and reasonable rates for wholesale electricity. This is because the trading strategies as a whole adversely affected the operations of Cal ISO or Cal PX markets and the calculation of the market-clearing price, which is dependent on participants engaging in bidding practices consistent with the Cal ISO and Cal PX tariffs and market rules, and not gaming the system or otherwise taking undue advantage of market rules.

All of the market participants identified in the Cal ISO study by its initial screen should be required to show cause why their behaviors did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violations or other appropriate remedies. Those market participants are as follows:

- Sempra
- San Diego Gas & Electric
- Morgan Stanley Capital Group
- Coral Power, LLC
- Powerex or British Columbia
- Enron Power Marketing Inc and its affiliate, Enron Energy Services Inc.
- Avista Energy Inc.

- Pacific Gas and Electric Company
- American Electric Power Services Corporation
- Duke Energy Trading & Marketing
- Mirant (previously known as Southern Company Energy Marketing, L.P.)
- Cargill-Alliant, LLC
- Idaho Power Company
- Puget Sound Energy
- Dynegy
- PGE Energy Services
- Calpine Corporation
- Modesto Irrigation District
- City of Glendale, California
- City of Azusa, California
- City of Riverside, California
- City of Pasadena, California
- City of Vernon, California
- Salt River Project
- Reliant
- Arizona Public Service Company
- Williams Energy Services Corporation
- PacifiCorp
- Automated Power Exchange
- Bonneville Power Administration (BPA)
- Portland General Electric
- Los Angeles Department of Water and Power (LADWP)
- Aquila
- Southern California Edison
- Citizens Electric
- Constellation Power Service
- Sierra Pacific Power Company

Staff also recommends that the Commission require the Cal ISO to provide transaction data that its analysis identified. The Cal ISO should also fully explain the screen that was used to identify the subject transactions. This information should also be made available publicly.

Enron's Business Model

In addition to the trading strategies discussed, Enron also created a marketing program based on the use of other entities' assets, thus avoiding large capital expenditures and the risk of owning its own resources. Business opportunities under Enron's business model were focused on smaller utilities, such as public utility districts, municipalities, qualifying facilities, and cogeneration facilities. Enron, using partnerships or alliances with others, gained market share, acquired commercially sensitive data, shared decisionmaking authority, and promoted reciprocal dealings and equity sharing of profits, among other things.

A company's business strategy is obviously devised by top management. In Enron's case, the business model is described in Enron documents from a 30,000-foot view as "Skilling's 'Enron Network' story." Enron formed business alliances or partnerships without filing the agreements with the Commission as required under its market-based rate authorizations. Its promotional literature entitled "Why customers choose Enron" was intended to convince others that using Enron, with its market knowledge of complicated markets such as in California, was a good business decision. Using Enron would save these entities labor and systems costs. Most importantly, using Enron would be profitable.

Under this business model, the nature of Enron's interaction with its business partners developed over time under a flexible master contract. For example, Enron[35] would first offer "consulting" services that allowed entities to outsource certain tasks rather than manage these tasks themselves. Enron gradually developed these relationships by expanding its services in an attempt to effectively control the assets of others in the decisionmaking process. Enron's compensation for these "services" usually started with a fee structure (e.g., a charge/MWh for

[35]From the documents in Staff's possession, it would appear that Enron may have used its jurisdictional and nonjurisdictional affiliates interchangeably; that is, at times, its nonjurisdictional companies performed the functions of jurisdictional companies. To the extent that a nonjurisdictional Enron affiliate in fact performed jurisdictional services, it was operating in the absence of a filed rate schedule and was in violation of the Federal Power Act. Revenues from such services would be refundable to the customers, at least in the absence of Enron's bankruptcy.

scheduling energy with the Cal PX). However, as the original relationship grew into a more comprehensive partnership, the compensation typically changed to an equity basis (share of profits) when the marketing of wholesale power was involved.

An Enron Services Handbook explains that in most instances, profits from marketing energy were split on a 50/50 basis while profits from capacity sales for ancillary services were split 25/75, with 25 percent going to Enron and 75 percent to its partner. One exception explained in the handbook involves certain energy sales with Puget when a sliding scale was used. If the sale was under $99/MWh, Enron received $5 and the remainder went to Puget. For sales between $700 and $750/MWh, Enron received $80 and the remainder went to Puget. While some forms of this rate structure may be appropriate under certain situations, this rate structure was used without notification to the Commission and without Commission approval.

Another e-mail dated December 24, 1999 explains the Big Foot deal as buying energy from Washington Water Power Company and scheduling it into California as a supplemental energy bid. As explained earlier, supplemental energy bids are associated with available capacity (e.g., generation used for ancillary services). The e-mail suggests that the traders may want to consider the following as part of the profit sharing: "If you buy from WWP and do real well on a supplemental, you might consider giving a few more dollars for their energy." With these types of profit-sharing arrangements, it is hard to argue that Enron's "partners" or "customers" did not have an understanding of how their profits were derived.

An undated Enron document entitled "Public Service of New Mexico California Service Overview" demonstrates a form of cooperative corporate behavior as follows:

> Enron and PNM will partner up and attempt to extract profits by purchasing day-ahead power in bilateral market and sinking the power in one of several markets: [...] The combination of these potential sinks should increase the ability of the partnership to find a profitable spread between the cost of purchasing the power and the revenues received from its eventual sale. Any profit/losses after all costs will be split 50 percent by each party. Enron will utilize its trading expertise, SC status, and California load to enhance this partnership. PNM will contribute its trading expertise and SW system to this partnership.

Enron's Business Partners

Various Enron documents indicate that Enron had service agreements or other contractual relationships with a number of entities, including the following:

- Energy West
- Montana Power Company
- Puget Sound Power and Lighting Company
- Powerex Corporation (formerly British Columbia Power Exchange Corporation)
- City of Redding, California
- City of Glendale, California
- Colorado River Commission (CRC)
- Las Vegas Cogeneration
- Washington Water Power Company (later named Avista)
- Valley Electric Association
- Public Service of New Mexico
- Grant Public Utility District
- Grays Harbor Paper Company
- Northern California Power Agency
- Modesto Irrigation District of Northern California
- TOSCO

Mr. Belden explained in an e-mail that Enron was able to develop alliances with other entities because:

> As regulatory changes, competitive markets, and institutions such as the California ISO increase the complexity of power trading, scheduling and settlements, more and more organizations are outsourcing certain tasks rather than manage these tasks themselves. Enron Power Marketing, Inc. (EPMI) is increasingly being called on to provide these services. Service transactions generally include ongoing EPMI performance obligations and greater daily customer interaction. Examples of these types of transactions include El Paso Electric, Valley Electric, Glendale, Enron Energy

> Services, and many others that are currently being contemplated or finalized.[36]

Gaining Control of Assets

A presentation at an Energy West Power Business Review Meeting characterizes the business strategy even more bluntly under a section entitled "Gaining Control of Assets." The presentation states:

> Currently pursuing two strategies. The first is gaining control of a variety of small resources or capabilities around the west. For example, the combination of El Paso Electric, Las Vegas Cogen, Valley Electric, and Glendale joint venture provide us with a useful mix of loads and resources in the southwest. These transactions require relatively little capital, but will require automated IT links to customers and more people in the logistics group.[37]

Essentially, Enron developed initial business relationships with entities, which over time evolved into alliances in which Enron could gain more control of decisionmaking in a way that maximized profits for itself and its business partners. As the summary of the Energy West Power Business Review Meeting states:

> (1) Currently provide scheduling services to El Paso Electric, Glendale, CFE (Mexico), Tosco, Washington Water Power, and Enron Energy Services.
>
> (2) Use scheduling as a platform that will dovetail with click trade and that will lead to larger transactions that will make more money (e.g., joint venture with the City of Glendale).[38]

An Enron Services Handbook contains a list of California market conditions with instructions for the Enron employee concerning whom to call and what steps the partner should follow in order to take advantage of a particular market situation. For example, if the prices in the California market are high, the Enron employee would refer to the handbook section entitled "Who do you call and what action to take?" The Enron employee first decides if the price is high enough to be profitable to the "customer." If it is profitable, the Enron employee implements the fat boy strategy: "generate or import and fake, or

[36]Staff Exhibit No. S-34 in Docket No. EL02-113-000.
[37]Staff Exhibit No. S-34 in Docket No. EL02-113-000.
[38]Staff Exhibit No. S-34 in Docket No. EL02-113-000. Click trading refers to the use of electronic trading on the EnronOnline platform.

increase, load." In this situation, the Enron employee could call Glendale, El Paso Electric, CRC, or Valley Electric and instruct them to increase imports into California; the handbook lists the transmission paths to be used. Redding and Tosco could be instructed to increase generation in northern California to implement this strategy. The pricing structure for this strategy specifies an even 50/50 split between Enron and its partner.

The instructions alert the Enron employee to check to see if there are also high ancillary service prices. In that situation, the Enron employee should "call Glendale, Puget and El Paso Electric to try to get ancillary services bids in" and "call customers and have them 'bid in' more."

The handbook also includes a list of steps to take if the prices in California are low. In this situation, the instructions call for the opposite strategy known as thin man—"artificially reduce load and export." The same counterparties are listed with corresponding delivery points for exporting their resources out of California. A similar pricing structure is also listed. Staff notes that in an August 22, 2000 West Mid-Market Quarterly Business Review, Enron states that it "touched/managed 3,500 MW/day."

Still other Enron documents describe arrangements that go beyond joint coordinated activity and describe total Enron control of decisionmaking authority. An Enron e-mail dated December 23, 1999 to Portland shift, with the subject "Valley Electric," states the following:

> We will be scheduling and making marketing decisions on Valley's behalf starting 1/1/2000[...]. There is an agreed on value sharing mechanism, in which Enron will get 40% of this "marketing value."

Enron literature describes how it planned to grow its relationship with parties. As its relationship grew, Enron collected data from the customer that it used for its own trading and marketing activities. For example, its strategy allowed "Enron to know as much or more about the customer's near term position." Finally, under this strategy, Enron planned to:

> Store operational data that the customer's merchant group would not normally be storing. Provide service around analysis and manipulation of data. [Enron North America] would own the data—a potential to lock customers in—if they leave [Enron North America] their data stays here.

In our Initial Report, the alliance between El Paso Electric Company and Enron was set for hearing in a proceeding apart from Docket No. PA02-2-000. That proceeding (Docket No. EL02-113-000) investigated whether Enron's use of El Paso Electric's facilities, pursuant to an unfiled service agreement, may have been improper. A settlement has been reached in that proceeding and El Paso Electric agreed to a substantial dollar settlement. That partial settlement, which is between El Paso Electric, the California Parties,[39] and the Trial Staff, does not address alleged violations of Enron and has not yet been certified to the Commission. Therefore, Staff recommends no further action against El Paso Electric.

Recommended Commission Responses

Staff believes that some of the Enron trading strategies violated the Cal ISO and Cal PX tariff provisions, which were in effect since operation began in April 1998. If a trade simply took advantage of a legitimate arbitrage opportunity, such as exporting a legitimate energy schedule, there would not be a tariff violation. If, however, in executing an Enron strategy a component was based on fictitious information that adversely affected market outcomes (such as death star or other transmission congestion strategies, get shorty, megawatt laundering simply to raise prices, load shift, or treating non-firm supply as firm supply), such activity could fall within the scope of the antigaming and/or anomalous market behavior provisions of the Cal ISO and Cal PX tariffs.[40] Therefore, Staff believes that it would be appropriate to issue an order to Enron and its partners (both public utilities and governmental entities) to show cause why these behaviors did not constitute gaming in violation of the Cal ISO and Cal PX tariffs, with disgorgement of unjust profits associated with the violation or other appropriate remedies. It makes no difference if the Enron partner or Enron itself executed the transaction. In either case, the misconduct falls under the Cal ISO and Cal PX tariffs.

All parties subject to the show cause orders[41] should be required to inventory all revenues related to the Enron trading strategies and

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[39]The California Attorney General, the California Electricity Oversight Board, the Public Utilities Commission of the State of California, Pacific Gas and Electric Company, and Southern California Edison Company (collectively, California Parties).

[40]Although the fat boy strategy included submitting false load schedules, it did not adversely affect the market outcomes, if the generation is simply bidding as a "price taker." To the extent the generator submitted strategic bids that affected the market outcomes, this would constitute market behavior prohibited under the Cal ISO tariff.

[41]Energy West; Montana Power Company; Puget Sound Power and Lighting Company; Powerex Corporation (formerly British Columbia Power Exchange Corporation); City of Redding, California; City of Glendale, California; Colorado River Commission (CRC); Las Vegas Cogeneration; Washington Water Power

demonstrate whether or not the transactions were legitimate as discussed in this chapter.

In summary, the evidence indicates that Enron, on its own, could not have implemented its trading strategies. It was only with the willing cooperation of others that these strategies could have been executed. Through Enron's direction, other entities both inside and outside California made business decisions that capitalized on market conditions in an effort to maximize profits from their assets on a coordinated basis. The coordination activity of Enron and its partners clearly changed market outcomes in a variety of ways. These parties capitalized on the complexities of the California market rules and structure. Market problems and dysfunctions were considered opportunities. As discussed above, Enron either acted on its partners' behalf or alerted others to act in a like manner in order to capitalize on market conditions that it anticipated or knew about. Profits from this activity were typically shared.

Enron systematically acted in partnership with others without the Commission's knowledge, and the joint behavior of these entities served to game the market. The collective behavior of these entities turned defects in market rules and market structures into profit-making opportunities for Enron and its partners.

A critical component of the Commission's market-based rate authorization involves a determination of an applicant's relative size in a market (market share). This determination is based on the amount of generation an entity either owns or has under contract, and the applicant is responsible for notifying the Commission in a timely manner of significant changes to its market share. According to the internal Enron documents, Enron controlled a significant amount of generation which it did not disclose in its filings before the Commission, and it never notified the Commission that changes in circumstances had occurred.

The preponderance of evidence reviewed by Staff during this investigation indicates that Enron and its affiliates intentionally engaged in a variety of market manipulation schemes that had profound adverse impacts on market outcomes. Due to this overwhelming evidence, Staff recommends that the Commission issue an order to show cause why its market-based rate authorizations and

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Company (later named Avista); Valley Electric Association; Public Service of New Mexico; Grant Public Utility District; Grays Harbor Paper Company; Modesto Irrigation District of Northern California; and TOSCO.

blanket certificate authority should not be revoked.[42] This order should cover Enron and its affiliates with the exception of Portland General Electric Company, which is the subject of an ongoing investigation in Docket No. EL02-114-000. Staff recommends that such revocation be made effective prospectively so that any preexisting contracts are not affected.

Filing Requirements

Staff is also aware that other entities conducted promotional activity similar to Enron in an attempt to form similar strategic alliances. For example, Sempra and Public Service of New Mexico may have competed with Enron in an attempt to perform similar services for El Paso Electric Company. Other evidence indicates that various entities may have had agreements with other market participants that had similar attributes as the Enron partnership agreements (e.g., sharing commercially sensitive information and coordinating activities). These entities include Avista and Turlock Irrigation District; Avista and the City of Riverside, California; Coral and the City of Glendale, California; and Coral and Sempra. To address this situation, Staff recommends that the Commission order all public utilities with market-based rates to file any past and present agreements with other entities having any of the characteristics described above within 30 days. This requirement applies to both sides of an agreement regardless of whether the entity is supplying or receiving service. The Commission can determine if such agreements cede operational control of assets or provide for an equity split of profits from unauthorized coordinated marketing activity. The Commission may need to clarify at what point Section 203 and 205 filings should be triggered. Failure to comply with this order should be dealt with harshly. For example, if entities do not provide this information and it is later discovered that such agreements exist, the Commission should immediately revoke market-based rate authorization for that entity.

[42]The Commission has already instituted formal proceedings to investigate Enron's ownership interest in various qualifying facilities, including Las Vegas Cogeneration Limited Partnership; Saguaro Power Limited; Victor Garden Phase IV Partnership; Sky River Partnership; Cabazon Power Partners LLC; Zond Wind System Partners, Ltd. Series 85-A; and Zond Wind System Partners, Ltd. Series 85-B.

Economic Withholding of Generation and Inflated Bidding During May to October 2000

Staff's preliminary analysis of the excessively high spot market-clearing prices as compared to the generation input costs (primarily natural gas costs) during May to October 2000 reveals what appear to be potential gaming violations, as defined in the MMIP of the Cal ISO and Cal PX tariffs. Staff has focused its analysis on this period because it covers the period of escalating prices prior to the October 2, 2000 refund effective date.

As explained earlier in this chapter, since the commencement of service in April 1998, the MMIP of the Cal ISO and Cal PX tariffs defined anomalous market behavior as including:

- Unusual trades or transactions.
- Pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, e.g., prices and bids that appear consistently excessive for or otherwise inconsistent with such conditions.
- Unusual activity or circumstances relating to imports from or exports to other markets or exchanges.

Clearing prices for the Cal ISO spot markets between May and October 2000 reached the then-current purchase price caps (that is, the Cal ISO would reject offers to sell power and/or energy to it at prices above these levels).[43] As explained below, the input costs for generation during this period do not support these excessively high spot market-clearing prices.

An example of the bidding behavior in question is the overall timing of the rise in spot market-clearing prices. As explained in Chapter IV of this Report (Figure IV-1), in May 2000 a disparity began to appear between the input costs of generation and the spot market-clearing prices for electricity. Over this time period, electric prices rose to levels often in excess of $500/MWh even though natural gas prices would have supported electric prices of only about $75/MWh. As explained in Chapter IV, the capital recovery requirement for a hypothetical new power project is between $16 and $19/MWh at a 60-

[43]The initial $750/MW cap was lowered to $500/MW on July 1, 2000. Subsequently, the purchase price cap was lowered to $250/MW on August 7, 2000.

percent plant factor.[44] Therefore, the fixed and variable cost of generation would not exceed $100/MWh. As opposed to a rise in input costs, the excessively elevated bid prices appear to be solely an attempt to raise prices and Staff views this as a form of economic withholding. For example, bids were at or near the $750/MWh bid cap in both the Cal ISO and Cal PX until it was lowered on July 1, 2000. Bids for the same units were at or near the $250/MWh cap later in the summer even though input prices had risen during the interim period.

The Commission's June 19, 2001 Order discussed the past performance of the single clearing price auction in California. The marginal unit of the least efficient unit dispatched (i.e., the unit with the highest heat rate) sets the clearing price that is paid to all generation in the market. In 1998 and 1999 (California's restructuring commenced operation on April 1, 1998), the California spot market produced average annual wholesale energy prices of $29 and $31/MWh, respectively. Staff notes that weather conditions were more favorable during this historical period, resulting in better hydro generation and lower system loads than during 2000 and 2001. Even with these major differences, the disparity in clearing prices before and during the crisis period is instructive.

Table VI-1 calculates the implied heat rates of units during the summer of 2000. The spot gas prices during this period ranged from $3.71 to almost $6.00. Dividing bid prices (ranging from $200 to $750/MWh) by the spot gas prices produces a rough approximation of the implied heat rate of a unit. These results show heat rates far beyond even the most inefficient units in California.

[44] See Chapter IV, footnote 11: California Energy Commission, *2000–2012 Electricity Outlook Report*, pp. 32-33.

Table VI-1. Implied Heat Rate

Month	Cost of Gas ($/MMBtu)	Price Cap ($/MWh)	Bid ($/MWh)	Implied Heat Rate (Btu/kWh)
May 2000	$3.711	$750	$200	53,894
			$300	80,841
			$500	134,735
			$750	202,102
June 2000	$4.658	$750	$200	42,937
			$300	64,405
			$500	107,342
			$750	161,013
July 2000	$4.499	$500	$200	44,454
			$300	66,681
			$500	111,136
Aug 2000	$5.103	$250	$200	39,193
			$250	48,991
Sep 2000	$5.975	$250	$200	33,473
			$250	41,841

Sources: Gas cost from *Gas Daily* for PG&E citygate and SoCal large packages; monthly cost is the average of daily prices for the month; California average is 50/50 north/south.

Staff notes that the Commission's April 26, 2001 Order (95 FERC ¶ 61,115 at 61,360) cites certain anticompetitive behaviors that would be prohibited under public utility sellers' market-based rate authorizations. First, bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit are prohibited. An example of this bidding practice is the so-called "hockey stick" bid in which the last megawatts bid from a unit are bid at an excessively high price relative to the bids on the other output from the unit. Another example cited in the order is excessively high bids for a single unit in a portfolio compared with the remainder of the portfolio, without any apparent performance or input cost basis.

The order explains a second category of prohibited bids—those that vary over time in a manner that appears unrelated to a change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis. An example of this is a bid that appears to change only in response to increased demand or reduced reserve margins, particularly if the timing of the bid is related to public announcements of system conditions or to timing of outages in a participant's portfolio.

Staff now concludes that such behavior was a violation of the MMIP. Staff's general focus was at a market level, comparing the spot clearing prices with underlying input costs. Staff concludes that input

costs and market fundamentals do not explain the excessive rise in clearing prices during the summer of 2000. The California Parties submitted an analysis of certain large market participants during this time period and reached similar conclusions.

The California Parties' Analysis of Bidding Practices by In-State Generators and Certain Importers

The California Parties submitted an analysis of the five large in-state generators together with an analysis of the bidding behavior of five importers: BPA, LADWP, Enron, Idaho Power, and Powerex. Staff's analysis of generation input costs and spot market-clearing prices is largely consistent with the California Parties' analysis. Based in large part on actual bid data that were submitted to the Cal ISO, Mirant, Williams, Dynegy, and Reliant had patterns of bidding units into the real-time market at or near $750 in May and June 2000, while the same units were bid at below $200 during September, after the Cal ISO cap was lowered to $250. The California Parties allege that these data indicate that the bid prices for these units in May and June exceeded costs by at least $500.

The California Parties state that the bid data indicate that Duke submitted bids during the summer of 2000 that were more consistent with actual marginal costs and contrast Duke's bidding behavior with the other market participants. However, Duke's bids in the Cal ISO's real-time market increased dramatically after the Commission's December 8, 2000 decision to allow sellers with bids over the price cap that were accepted by the Cal ISO to be paid their bid price. The California Parties also argue that this pattern continued during the subsequent period when spot sales were made directly to CERS.

The California Parties allege that other sellers in their study demonstrated noncompetitive bidding patterns consisting of bid price spikes and prolonged elevation of bid prices. In particular, they note that the Cal ISO declared a system emergency on 6 different days in June 2000 (June 13, 14, 26, 27, 28, and 29) and that bid price spikes were submitted during these emergencies by Williams, Dynegy, Mirant, Reliant, Powerex, LADWP, Idaho Power, and BPA. Similar results were shown for the 11 days on which the Cal ISO declared system emergencies in May, July, and August 2000. The California Parties also allege that on various days, two or more of these sellers submitted bid price spikes. The following is a summary of the California Parties' analysis of the various market participants.

Reliant

The California Parties allege that Reliant submitted pronounced hockey stick bids for four of its units during the May-June period. The average bid spans (the price difference between the lowest-priced bid segment and the highest-priced bid segment) were as high as $186/MWh. An example of bid price spikes occurred between May 22 (the day of the Cal ISO-declared emergency) and May 24. In June, there were bid price spikes on days when the Cal ISO declared emergencies: June 13, 14, 26, 27, 28, and 29, and June 21-22 (Reliant's withholding period). Reliant's bids reached the price cap levels of $750, $500, and $250.

Mirant

The California Parties characterize Mirant's bidding behavior during the summer of 2000 as persistently high for some of its units and hockey stick bidding for other units. For example, Mirant's Potrero Units 4, 5, and 6 were bid at or near the price cap in most hours. In other words, the units were bid with a pattern that simply tracked the price caps, i.e., near $750 at first, then near $500, and, starting in August, near $250. According to the California Parties, Mirant increased its bid prices on all or a large number of bid quantities on May 2-5, 15-16, 19-21, 22 (Cal ISO-declared emergency), 23, 28, and 31. The California Parties identify other similar examples and examples of persistent high bidding patterns throughout the summer of 2000.

Dynegy

The California Parties allege that Dynegy generally bid its combustion turbines into the real-time market at very high prices, especially during June and July 2000. They also allege that during May through July, hockey stick bidding was used with an average bid span (price difference between the lowest-priced bid segment and the highest-priced bid segment) in excess of $300. Examples of high spikes in bid prices occurred on May 4-5, 21-27, and 30-31. Overall, in June, Dynegy submitted very high bid prices for its units. Only 3 of its 22 units bid into the real-time market had an average bid price of below $200, while others averaged close to $700. Other examples of noncompetitive bidding throughout the summer were identified.

Williams

Overall, the California Parties allege that Williams bid very high prices for all of its units. Also, substantially similar units are bid in different ways that cannot be explained on a cost basis. For example, in May Alamitos Unit 5 was bid at an average price of $668/MWh, whereas Redondo Unit 7 was bid at an average price of $234/MWh. During May 2000, the California Parties allege that Williams' bid prices spiked on May 1, 3-5, 6, 10, and 21-23 (including during the Cal ISO-declared emergency on May 22). Bid price spikes in June included June 3, 12, 13-14 (Cal ISO-declared emergencies), 20-22, and 26-29 (Cal ISO-declared emergencies). Similarly, during July, bid price spikes were alleged to have occurred on July 7, 13-14, 18, and 26, and during declared emergencies on July 19-20, 24-25, 27, 28, and 31.

Enron

The California Parties allege that from January to April 2000, Enron bid into the real-time market almost exclusively at the then-prevailing Cal ISO cap of $750. This pattern appears to persist through the summer of 2000 but with more variability.

Powerex

The California Parties allege that during the Cal ISO-declared emergency on May 22, 2000, Powerex withdrew approximately 1,000 MW of energy that it typically offered to the real-time market, and therefore allegedly played a role in causing this emergency. On other days, Powerex's bids would vary by 1,500 to 2,000 MW from hour to hour. On June 15, 2000, Powerex submitted large, infeasible schedules over various interfaces into California (over 10,000 MW) into the real-time market for several hours at or near $750. Powerex changed the nature of its bids in the following hour and bid almost 5,000 MW but at negative $750 (meaning that a reduction of generation will cost $750). This pattern was repeated later in the day.

On December 12, 2000, following the Commission's order to institute a soft cap in place of the $250 cap, Powerex increased its bids by approximately $500 to an average of approximately $750, with a number of bids being submitted over $1,100.

LADWP

According to the California Parties, LADWP employed bidding patterns that removed supply from the real-time market for small periods, and spiked the bid prices on all or a large number of its bid quantity for small periods. For example, on May 21, 2000, the day preceding the Cal ISO-declared emergency, LADWP raised all bids into the real-time market reaching $750/MWh. Then on May 23-24, LADWP's bid prices dropped to $200/MWh. LADWP submitted bid price spikes on 6 other days that were Cal ISO-declared emergencies (June 14, 27, 28, and 29, and July 24 and 25). The California Parties cite other nonemergency days on which LADWP submitted bid price spikes, again reaching the bid cap.

Idaho Power Company

According to the California Parties, the bidding strategies of Idaho Power resembled those of LADWP and Powerex. From May to July, the California Parties identified 23 days, including 8 days that are Cal ISO-declared emergencies, on which Idaho Power submitted bid price spikes. Idaho Power's bids reached the $750, $500, and $250 levels established by the price caps during this period.

BPA

According to the California Parties, BPA was an active participant in the real-time market through the summer of 2000. Bid price spikes were observed on May 23-25 and 27; June 1-3, 28-29 (Cal ISO-declared emergencies), and 30; and July 1. Starting after the May 22 emergency, BPA submitted bids at the $750, $500, and $250 cap levels during the various price cap periods.

Responses Filed by the In-State Generators and Importers

The in-state generators and importers filed reply comments and rebuttal testimony and exhibits. These entities raise various objections and argue that there was no requirement under the Cal ISO or Cal PX tariffs or protocols or Commission regulations in effect that generators bid at their marginal cost of production. They conclude that the California Parties have failed to demonstrate that any of the bidding practices constitutes withholding. Similarly, there were no restrictions on a seller's ability to bid high. Mirant states that after the

Commission issued the April 26, 2001 Order, it stopped using hockey stick bidding.

In response to the California Parties' allegations of noncompetitive bidding behavior by these entities, they renew arguments previously made in various proceedings before the Commission in an effort to justify their high bids. Their explanations include: (1) the difficulty in determining the marginal cost of a unit, particularly with respect to startup costs; (2) because there is no capacity market in California, using a marginal cost standard is inappropriate; and (3) a marginal cost standard does not recognize market uncertainty, "scarcity rents," and legitimate opportunity costs during the summer of 2000. Examples of plants with opportunity costs are limited run-time units, including fossil-fuel plants in California that have operating time limits in their air emissions permits or that must acquire scarce emissions credits. The generators maintain that such units should be bid at the price one would expect to receive during the highest-priced period in the future. They also argue that hockey stick bidding is appropriate for the last increment of a unit because it recognizes the risk of a forced outage. In this event, the seller must purchase replacement energy to meet its commitment. They also argue that it is appropriate to hold units in reserve as a physical hedge against the unexpected loss of a unit.

Staff finds that these arguments are unpersuasive and do not adequately explain the dramatic rise in prices starting in May 2000. Such high bids and clearing prices far exceed the level needed to recover the capacity costs of generation. Market uncertainty existed prior to and after the summer of 2000, and this does not explain the price spike. The argument regarding opportunity costs is not persuasive because the units were first bid at $750 and then progressively lower through the summer of 2000. Using hockey stick bidding plus a physical hedge as insurance for a possible forced outage appears duplicative. Finally, Staff has explained that the MMIP was part of the Cal ISO's and Cal PX's filed rate schedules.

Recommended Commission Responses

Staff recommends that the Commission issue an order to LADWP, Dynegy, Mirant, Reliant, Williams, BPA, Powerex, Enron, and Idaho Power directing them to show cause why their behavior during May 2000 through October 2, 2000 does not constitute a violation of the Cal ISO or Cal PX tariffs, with disgorgement of unjust profits associated with the violation or other appropriate remedies.

The market participants discussed in this section of the Report displayed bidding patterns that were higher early in the summer (May and June) than in subsequent summer months even though input costs

(such as the cost of natural gas) nearly doubled during that same time period. The data suggest that these market participants' high bidding behavior was not disciplined by their cost inputs; they simply bid the then-existing price cap—riding the cap from $750 to $500 and then to $250. Taking the example of a hypothetical unit with a 15,000 Btu/kWh heat rate, a bid of $250/MWh in September when gas costs were $6/MMBtu would generate $90 for the cost of fuel and $160 as a margin to recover fixed costs, scarcity, etc. A $250 bid in May for the same unit when gas costs were $3.72/MMBtu would generate $56 for the cost of fuel and $194 as a margin to recover fixed costs, scarcity, etc. Conversely, a $750 bid in May would produce a margin of approximately $700.

Staff notes that during the summer of 2000, legitimate scarcity costs should have increased from May to September as the California ISO weather-dependent demand increased. Yet, bidding patterns of these generators show that their bids were not directly related to load levels and associated scarcity levels. Staff also notes that the creditworthiness issue did not arise until after the summer period, so credit risk is not valid support for anomalous bids during this period. Similarly, the emission costs rose steadily in 2000 as the year progressed. If suppliers were willing to voluntarily supply at $250 in August and September as cost inputs rose dramatically, their bids above this level earlier in the summer (when cost inputs were far less) are highly questionable. However, Staff believes that there is reasonable support for prices that include a scarcity premium above marginal costs to reflect the severe scarcity that occurred during the summer of 2000. Bids at the $250 level during August and September reflect the supply/demand imbalance in the Western markets, emission restrictions in the California market, and risks involved in pushing older generating units to their operating limits day after day. Given these circumstances, Staff recommends that the Commission investigate all bids over $250 during the period May 1 through October 1, 2000.

During the summer of 2000, Staff notes that one large in-state generator (Duke) submitted bids that appear to be more representative of its actual generation input costs. A possible explanation is that during this time period, unlike the other four large in-state generators, Duke was not heavily exposed to the spot market. During this period, Duke had committed a large amount of its generation to forward purchases. While Duke may have benefited during this period, like all other entities that received a clearing price above their bid, this does not constitute a violation of the Cal ISO or Cal PX tariffs. As noted, Duke's high bids are covered by the refund proceeding.

Staff notes that the transactions with the Cal ISO during the October 2, 2000 forward period are already subject to refunds. This appears to be an appropriate remedy for excessively high bidding. The Commission's June 19, 2001 Order discussed an example of Duke's high bidding behavior in February 2001. In that order, the Commission noted that Duke had bid $3,880/MWh. Duke maintained that this bid was a negotiating tool to recover payment for prior transactions and that it included a credit premium. The Commission noted that this premium exceeded Duke's variable costs by an order of magnitude. The Commission found that Duke's bidding at multiples of its marginal costs in an attempt to recover past-due amounts can in no way be found to be just and reasonable. The entire period in which Duke submitted high bids to the ISO is covered by the refund proceeding.

Finally, as for any transactions with CERS, Staff notes that such transactions are not under the Cal ISO tariff and are therefore not subject to the MMIP. The California Parties submitted a comprehensive list of all transactions with CERS in Exhibit No. CA-197. Staff's review of these data indicates that Duke's transactions, like most transactions with other parties, were under the Western Systems Power Pool Agreement. Therefore, Staff recommends that Duke not be subject to a show cause order.

Physical Withholding of Generation

During two days in June 2000, certain Reliant employees reduced the quantity of megawatts offered to the Cal PX on a day-ahead basis below the amount that normally would have been offered under the existing market conditions. Specifically, on Monday, June 20, Reliant reduced the capacity it bid into the Cal PX for delivery on June 21 by approximately 1,000 MW. Reliant increased only slightly the amount of capacity it bid into the Cal PX on June 21 for delivery on June 22. Reliant elected to perform discretionary maintenance on generating units whose output otherwise would have been offered to the Cal PX for those days.

By order dated January 31, 2003, in Docket No. PA02-2-001, the Commission approved a Stipulation and Consent Agreement (Agreement) between Staff conducting the investigation in this proceeding and Reliant resolving the actions taken on these two days with respect to sales that would have occurred in the Cal PX market. Under the Agreement, Reliant agreed to pay approximately $13.8 million directly to customers of the Cal PX that purchased energy in the Cal PX's day-ahead market on June 21 and 22. As explained in the

order, the payment reflects the worst-case scenario of the maximum effect of Reliant's withholding on the California market.

Since the issuance of this order, various entities have submitted evidence regarding other alleged incidents of physical withholding by various market participants in the California markets. These allegations are not dealt with in this Staff Report. The issue of potential physical withholding is the subject of a separate and ongoing investigation.

Reliant and BP Energy Traders Appear To Have Engaged In Coordinated Efforts To Manipulate Market Prices

In the course of the investigation, Staff uncovered instances of traders from Reliant and BP Energy (BP) apparently coordinating their efforts to manipulate western electricity prices. Specifically, on three occasions a trader from BP contacted a Reliant trader and asked him to buy electricity from an offer he was going to place on an electronic trading platform (Bloomberg). The BP trader would then sell the power back to the Reliant trader at the same price, but the transaction would not take place on the electronic trading platform.

On at least one of the occasions, the BP trader is seemingly manipulating the market price (in this case, electricity delivered at Palo Verde, a large trading hub in Arizona) in order to affect the value of his trading position for mark-to-market accounting purposes. The Reliant trader appears to have no particular interest in manipulating the market price; he simply goes along with the BP trader's scheme. The evidence comes from recorded telephone conversations and transcripts provided to Staff by Reliant under Docket No. PA02-2-000.

Staff has evidence that in April 2000, the BP trader contacted the Reliant trader and asked him to do him a favor. The BP trader (1) will offer to sell electricity on the Bloomberg electronic platform, (2) the Reliant trader will buy at the posted price, and (3) the BP trader will buy back the power (off the exchange) at the same price to negate the deal. The BP trader goes on to explain that he is trying to move the market price to $43.10 but no one will buy it at that price, so he needs the Reliant trader to "lift his offer" in order to increase the price.

Our evidence indicates that several days later, the same BP trader contacted the same Reliant trader and offered him a similar proposal. Again, the BP trader is trying to manipulate the price in order to

increase the value of his trading position under the company's mark-to-market accounting.

The BP trader goes on to explain that they are marking their books on the October Palo Verde price. He notes that power for delivery in October at Palo Verde had traded as high as $44. He wants to move the price even higher because of his long position. He indicates that he will post an offer to sell at $44.15 and asks the Reliant trader to lift that offer and then he will buy it back from him at the same price. The BP trader then posts the offer on Bloomberg.

Later that day, the BP trader instructs the Reliant trader to lift the offer because he senses the market beginning to move. The Reliant trader lifts the offer and asks the BP trader what they should do next. The evidence indicates that the BP trader informed the Reliant trader that he will buy the power back at the same price.

Significantly, when Staff asked BP for information and telephone transcripts of these events, BP simply stated that it had no information regarding the activity of its trader.

One of the concerns regarding the apparent price manipulation described above is that it occurred at an important trading hub (Palo Verde) that was presumed to be very liquid and thus not subject to price manipulation. Electricity price indices are a critical part of the market price formation process, and this market was clearly being manipulated.

Therefore, Staff recommends that the Commission initiate proceedings to revoke Reliant's and BP's ability to sell power at market-based rates.

Spot Prices in the Pacific Northwest—Docket No. EL01-10-000, et al.

The proceeding in Docket No. EL01-10-000, et al. was established to "facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest" for the period December 25, 2000 through June 20, 2001. On September 24, 2001, the presiding Administrative Law Judge (ALJ) issued her proposed findings of fact and recommendations. The ALJ found that while California spot electricity prices affected electricity prices in the Pacific Northwest, prices in the region were driven up by a combination of factors, including reduced hydro generation due to the drought, increased demand, and relatively high

natural gas prices. In essence, the ALJ concluded that the record did not support allegations of market manipulation.

In numerous orders, the Commission has stated that the spot markets in the West are integrated. Staff's Final Report concludes that the California spot electricity markets were manipulated. This chapter explains that a variety of strategies were used by Enron and various market participants in an effort to manipulate various market outcomes in California. The manipulations used a variety of techniques, including submitting false information, creating false transmission congestion, and importing and exporting power into and out of California. All of these manipulations may have affected spot prices in the Pacific Northwest.

During the course of its investigation, Staff sent a blanket data request to all sellers of electricity in the West for specific transaction data, including actual monthly sales data for bilateral transactions at the Mid-Columbia (Mid-C) trading hub and the California-Oregon Border (COB) trading hub. These are the two primary trading locations in the Pacific Northwest for bilateral electric sales and purchases. These transaction data indicate that, especially during the refund period (January 2001 to June 2001), there was a significant increase in spot prices in the Pacific Northwest similar to the rise in spot prices in California. Because there are no single clearing price markets in the Pacific Northwest, Staff has used bilateral sales of 1 month or less that are entered into no more than 1 month in advance of delivery for spot transactions. Staff has calculated average monthly implied heat rates based on the cost of gas at Malin and Sumas (the two main gas hubs that correspond to power delivered at Mid-C and COB). To perform this calculation, Staff divided the average cost of spot sales (approximately 650 transactions) by the average monthly cost of gas. Table VI-2 illustrates Staff's results.

Table VI-2. Implied Heat Rate

Delivery Month	Cost of Gas ($/MMBtu)	Average Spot Price ($/MWh)	Implied Heat Rate
January 2001	$9.08	$393	43,282
February 2001	$7.99	$275	34,418
March 2001	$6.20	$291	46,935
April 2001	$7.32	$293	40,137
May 2001	$4.79	$318	66,388
June 2001	$3.33	$285	85,585

Staff's preliminary analysis indicates that the run-up of spot prices in the Pacific Northwest region is not fully explained by input prices such as the cost of natural gas. The transaction data reviewed by Staff indicate that during the previous 7 months (May to December 2000) there were approximately 2,000 transactions with average monthly prices ranging from $51/MWh to $167/MWh.

Staff has also analyzed the spot sales transaction data in order to estimate the variable cost of production and the remainder, which could be considered the capital cost recovery of the generation plant. As previously discussed, the capital recovery requirement of a new combined cycle gas turbine is between $85 and $100/kW per year, or approximately $16 to $19/MWh at a 60-percent plant factor (see Table VI-3).

Table VI-3. Estimated Capital Cost Recovery

Delivery Month	Cost of Gas ($/MMBtu)	Average Spot Price ($/MWh)	Cost Recovery at 15,000 Heat Rate	Remainder for Capital Cost
January 2001	$9.08	$393	$136.20	$256.80
February 2001	$7.99	$275	$119.85	$155.15
March 2001	$6.20	$291	$93.00	$198.00
April 2001	$7.32	$293	$109.80	$183.20
May 2001	$4.79	$318	$71.85	$246.15
June 2001	$3.33	$285	$49.95	$235.05

An analysis of the transaction data indicates that, assuming a heat rate of 15,000 Btu/kWh to generate the spot sales, the average monthly

sales prices recover the cost of gas and the remainder (the last column of the table) would far exceed the capital costs needed for the plant.

Recommended Commission Responses

Based on Staff's preliminary analysis, Staff recommends that the Commission remand this proceeding back to the ALJ in order to consider the additional evidence received after her initial findings.

VII. Wash Trading on EnronOnline

Several energy trading companies, including CMS Energy, Dynegy, Williams, and Reliant, have admitted publicly to engaging in "wash trades." As a result of our analysis of EnronOnline (EOL) data, Staff, with assistance from Hendrik Bessembinder, Blaine Huntsman Chair in Finance, Eccles Business School, University of Utah, has also identified Enron and others as participants in wash trading activities. In fact, Enron's use of its EOL platform created a fertile ground for wash trading that resulted in multiple forms of manipulation in energy markets.

The term "wash trade" is generally defined as a *prearranged* pair of trades of the same good between the same parties, involving no economic risk and no net change in beneficial ownership. These trades expose the parties to no monetary risk and serve no legitimate business purpose. Potential motives for wash trading are numerous. Wash trades might be used to create the illusion that a market is liquid and active, or to increase reported trading revenue figures. Wash trades might be arranged at prices that diverge from the prevailing market in an attempt to send false signals to other market participants. Alternatively, the intent might be to affect the average or index price reported for a market, which in turn could benefit a derivatives position or affect the magnitude of payments on a contract linked to the index price.

In general, wash trading is viewed as damaging to the integrity of a market and has the potential to mislead a host of market stakeholders (including competitors, regulators, analysts, and investors) through the various forms of manipulation outlined above. Although the Commission has no regulations on wash trading, wash trades are prohibited in markets regulated by the Commodity Futures Trading Commission. This chapter provides statistical evidence indicating that wash trading in energy products was more common than previously recognized.

Wash Trading on EnronOnline

The statistical portion of this chapter describes wash trades in natural gas and electricity products on the EOL trading platform from January 2000 to November 2001. This study focuses on EOL trades in which both the buy and sell transactions were recorded in a single database. It seems likely, though, that market participants who intend to use wash

trades for illegitimate purposes would be inclined to use methods that did not create a single electronic record of both transactions. The alternatives might include direct bilateral negotiation of both trades by telephone, or completion of one leg by telephone or an alternate electronic platform while completing the other leg on EOL. Our definition of wash trading considers trades that occurred within the same product, at the same price, in the same volume, and at nearly the same time (within 2 minutes of one another).

It should be recognized that a company might enter an offsetting pair of trades on EOL for legitimate business purposes. For example, a company anticipating unseasonably warm weather might purchase a quantity of power, only to resell it later as actual weather conditions are milder. Therefore, it is possible that this report includes some "false positives"—paired trades that appear to be inappropriate wash trades but were not. However, given the facts in the specific examples of wash trading described herein, we believe the manipulative nature of these examples is obvious.

Choice Markets

EOL market makers are traders assigned to always quote both a bid price and an offer price, representing Enron's willingness to always buy or sell gas during market hours. Our data analysis and interviews with market makers indicate that they sometimes elected to set the bid-offer spread to zero, which they referred to as making a "choice market." Choice markets may, in effect, have been an invitation to EOL customers to engage in wash trading. The raw data used in our analysis do not include bid and ask quotes, so it is not possible to directly identify periods of choice (zero spread) markets. However, Staff identified all sequences of trades that occurred during likely choice markets based on the following criteria: (1) all trades in the sequence occurred at identical prices, (2) at least one trade in the sequence was an EOL buy and at least one was an EOL sell, (3) the sequence contained at least four trades, and (4) all trades in the sequence are for the same product at the same volume.

Tables VII-1 and VII-2 provide information about EOL trading activity during choice market periods. Table VII-1 reports activity by calendar month, revealing that choice market trading on EOL increased steadily over time. In fact, 45 percent of all choice market trading in gas products and 54 percent of all choice market trading in electricity markets occurred during the last 3 months (September to November 2001) of the 21-month sample. These 3 months coincide with the period of time leading up to Enron's filing for bankruptcy.

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The reasons for this upward trend in choice market trading activity are unclear; however, it may have been an attempt to prop up or otherwise maintain Enron's presence in the market.

Table VII-1. Trades Completed During Choice Markets, by Month

Gas Trades				Power Trades			
Year	Month	Choice Trades	Percent of Total	Year	Month	Choice Trades	Percent of Total
2000	1	749	1.4	2000	1	82	0.5
2000	2	1024	1.9	2000	2	134	0.8
2000	3	1835	3.4	2000	3	195	1.2
2000	4	958	1.8	2000	4	101	0.6
2000	5	887	1.7	2000	5	41	0.2
2000	6	776	1.5	2000	6	23	0.1
2000	7	754	1.4	2000	7	102	0.6
2000	8	1209	2.3	2000	8	222	1.3
2000	9	1046	2.0	2000	9	268	1.6
2000	10	1126	2.1	2000	10	513	3.1
2000	11	1256	2.4	2000	11	165	1.0
2000	12	707	1.3	2000	12	36	0.2
2001	1	1218	2.3	2001	1	344	2.1
2001	2	1314	2.5	2001	2	378	2.3
2001	3	2844	5.3	2001	3	536	3.2
2001	4	1656	3.1	2001	4	412	2.5
2001	5	2015	3.8	2001	5	452	2.7
2001	6	2117	4.0	2001	6	614	3.7
2001	7	2129	4.0	2001	7	1129	6.7
2001	8	3721	7.0	2001	8	1894	11.3
2001	9	6859	12.8	2001	9	2366	14.1
2001	10	10511	19.7	2001	10	4534	27.0
2001	11	6734	12.6	2001	11	2231	13.3
Total		53,445		Total		16,772	

Choice market trades were identified as a sequence of at least four consecutive trades at the same price, with at least one buy and one sell included in the sequence. The table reports the number of EOL gas and power trades completed during choice markets, by trading month, from January 2000 to November 2001.

Table VII-2 reports the number of choice market trades completed by several individual Enron market makers. Our analysis indicates that certain market makers created choice markets rather frequently. In gas products, 19,564 choice market trades (36.6 percent of the total) were executed by a single EOL market maker, and 6,285 choice market trades (11.8 percent of the total) were executed by a second EOL market maker. In power products, the most choice market trades executed by any single EOL market maker was 1,814, which was 10.8 percent of the total choice market trades. It is important to note that the total gas trades in choice markets exceed the power trades by greater than 3 to 1. This could be explained by the greater volume of gas trading that occurred on EOL as compared to power trading.

Table VII-2. Trades Executed During Choice Markets, by Trader

Gas Trades		Power Trades	
Enron Trader	Total Trades During Choice Markets	Enron Trader	Total Trades During Choice Markets
Trader A	19,564	Trader K	1814
Trader B	6285	Trader L	1373
Trader C	2567	Trader M	1219
Trader D	2431	Trader N	1159
Trader E	2382	Trader O	1008
Trader F	1710	Trader P	934
Trader G	1608	Trader Q	861
Trader H	1127	Trader R	834
Trader I	884	Trader S	731
Trader J	823	Trader T	612
All Traders	53,445	All Traders	16,772

The table reports the top 10 Enron gas and electricity traders in terms of the total trades executed during choice markets between January 2000 and November 2001.

Wash Trades Within Choice Markets

Using the choice market data shown above, Staff identified all wash trade pairs that occurred within these choice market events based on the additional criteria that both legs of potential wash trades involved the same counterparty and occurred within 2 minutes of each other. Since these trades occurred during choice markets, the previously mentioned criteria that these trades involve the same product, same price, and same volume also apply.

By focusing only on wash trades that occurred within choice markets and within a sequence of at least four trades, we significantly limited the total number of wash trades identified. For example, a deliberate wash trade that included only a single pair of trades between two divergently priced transactions would not have met our criteria for a choice market nor, consequently, for a wash trade. However, by focusing on wash trades that occur within choice markets and within a sequence of four or more trades, we significantly increase the likelihood that the trades we select are indeed wash trades—a single pair of trades not part of a sequence of four or more trades would not be considered.

Tables VII-3 through VII-8 provide information about wash trades completed during periods of choice markets. It is important to note that each wash trade represents a matching pair of trades. Therefore, for a

trader to complete 10 wash trades, he would actually need to execute 20 trades (10 buys and 10 sells). These trade pairs all involved the same counterparty, the same quantity, and the same product, and occurred within 2 minutes of each other. Also, since they occurred during a period of choice markets as previously defined, each leg of the wash trade as well as any intervening trades occurred at a common price. The fact that these trades occurred during choice markets makes it likely that they were intended to inflate reported trading volumes and/or influence market indices.

Table VII-3 reports the number of wash trades by month. In general, these data reveal a trend in which more wash trades occurred later in time. Only 5 percent of gas wash trades and 1 percent of power wash trades occurred during the first 4 months (January to April 2000) examined, while 42 percent of gas wash trades and 46 percent of power wash trades occurred during the last 4 months (August to November 2001) examined. An exception is the month of October 2000 (highlighted in bold), when 27.5 percent of power wash trades occurred.[1]

[1]This cluster of wash trading is linked to a previously noted promotional campaign in which a big screen television was awarded as a prize to the counterparty that generated the most trading activity. See "Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations: Published Natural Gas Price Data and Enron Trading Strategies," Federal Energy Regulatory Commission Staff Report, August 2002, p. 54.

Table VII-3. Wash Trades Completed During Choice Markets, by Month

Gas Trades				Power Trades			
Year	Month	Wash Trades	Percent of Total	Year	Month	Wash Trades	Percent of Total
2000	1	1	0.3	2000	1	0	0.0
2000	2	4	1.1	2000	2	3	0.8
2000	3	6	1.6	2000	3	1	0.3
2000	4	8	2.1	2000	4	1	0.3
2000	5	3	0.8	2000	5	0	0.0
2000	6	2	0.5	2000	6	0	0.0
2000	7	1	0.3	2000	7	11	2.8
2000	8	11	2.9	2000	8	10	2.6
2000	9	8	2.1	2000	9	5	1.3
2000	10	5	1.3	2000	10	106	27.5
2000	11	11	2.9	2000	11	0	0.0
2000	12	19	5.0	2000	12	1	0.3
2001	1	6	1.6	2001	1	5	1.3
2001	2	13	3.4	2001	2	5	1.3
2001	3	38	10.1	2001	3	13	3.4
2001	4	13	3.4	2001	4	6	1.6
2001	5	15	4.0	2001	5	8	2.1
2001	6	29	7.7	2001	6	12	3.1
2001	7	25	6.6	2001	7	23	6.0
2001	8	35	9.3	2001	8	42	10.9
2001	9	42	11.1	2001	9	46	11.9
2001	10	50	13.2	2001	10	49	12.7
2001	11	33	8.7	2001	11	39	10.1
Total		378		Total		386	

The table reports the number of wash EOL gas and power trades completed during choice markets, by trading month, from January 2000 to November 2001.

Table VII-4 reports the EOL market makers involved in the most wash trades. In gas products, 1 trader executed 111 wash trades (29.4 percent of the total) and a second trader executed 73 wash trades (19.3 percent of the total). In power markets, 1 EOL market maker executed 102 wash trades (26.4 percent of the total), a second market maker executed 36 wash trades (9.3 percent of the total), and a third completed 32 wash trades (8.3 percent of the total). The fact that an individual trader would be linked to more than 25 percent of all wash trades in a product is significant evidence that wash trading on EOL was not simply a coincidence or a random occurrence.

Table VII-4. Wash Trades Completed During Choice Markets, by Trader

Gas Trades			Power Trades		
Enron Trader	Total Wash Trades During Choice Markets	Percent of Total	Enron Trader	Total Wash Trades During Choice Markets	Percent of Total
Trader A	111	29.4	Trader K	102	26.4
Trader B	73	19.3	Trader L	36	9.3
Trader C	24	6.3	Trader M	32	8.3
Trader D	16	4.2	Trader N	16	4.1
Trader E	13	3.4	Trader O	15	3.9
Trader F	11	2.9	Trader P	13	3.4
Trader G	11	2.9	Trader Q	12	3.1
Trader H	10	2.6	Trader R	12	3.1
Trader I	10	2.6	Trader S	11	2.8
Trader J	9	2.4	Trader T	10	2.6
All Traders	378		All Traders	386	

The table reports the numbers of wash trades during choice markets between January 2000 and November 2001 for the 10 most frequent Enron traders.

Table VII-5 reports the counterparties who engaged in the largest numbers of EOL wash trades. In gas products, Entergy-Koch Trading, LP completed 61 wash trades (16.1 percent of the total). In power products, Aquila Energy Marketing Corporation completed 112 wash trades (29 percent of the total). Again, the high percentage of involvement in wash transactions is significant evidence that certain EOL counterparties regularly and knowingly participated in wash trades.

Table VII-5. Wash Trades Completed During Choice Markets, by Counterparty

Gas Trades			Power Trades		
Counterparty	Total Wash Trades During Choice Markets	Percent of Total	Counterparty	Total Wash Trades During Choice Markets	Percent of Total
Entergy-Koch Trading, LP	61	16.1	Aquila Energy Marketing Corporation	112	29.0
Reliant Energy Services, Inc.	25	6.6	Williams Energy Marketing & Trading Comp	27	7.0
Cook Inlet Energy Supply L.L.C.	22	5.8	Idaho Power Company, dba IDACORP Energy	25	6.5
AEP Energy Services, Inc.	21	5.6	Cinergy Services, Inc.	13	3.4
MidAmerican Energy Company	21	5.6	American Electric Power Service Corporat	9	2.3
Mieco Inc.	19	5.0	Dynegy UK Limited	9	2.3
PG&E Energy Trading-Gas Corporation	15	4.0	EPMI Short Term New England (Enron Affiliate)	9	2.3
Coral Energy Holding, L.P.	11	2.9	El Paso Merchant Energy, L.P.	8	2.1
Aquila Energy Marketing Corporation	9	2.4	IDACORP Energy L.P.	8	2.1
Other Companies	174	46.0	Other Companies	166	43.0
Total	378		Total	386	

The table reports the top Enron counterparties in terms of the total wash trades completed during choice markets between January 2000 and November 2001.

Table VII-6 reports delivery locations for wash trades. Some (34 percent of gas and 17 percent of power) wash trades were for financial products without physical delivery locations. Henry Hub was by far the most common delivery point for gas wash trades (31 percent of the total), while Mid-Columbia (24 percent), Cinergy (17 percent), and the California-Oregon Border (14 percent) were the most frequent delivery points for power wash trades.

Table VII-6. Wash Trades Completed During Choice Markets, by Delivery Location

Gas Trades			Power Trades		
Location	Wash Trades at Location	Percent at Location	Location	Wash Trades at Location	Percent at Location
Financial	129	34.1	Mid Columbia	92	23.8
HHub	118	31.2	Financial	66	17.1
NGPL NICOR	24	6.3	Cinergy	54	14.0
SoCal Topock EPNG	20	5.3	COB North/South	49	12.7
NBP	11	2.9	Palo Verde	30	7.8
Opal	10	2.6	German Grid	23	6.0
ANR SE Transmission	8	2.1	PJM Western Hub	18	4.7
NIT - AECO	8	2.1	Entergy	13	3.4
NNG Demarc	8	2.1	NEPOOL-PTF Power (3/1/00)	11	2.8
EPNG Keystone Pool	6	1.6	NBP Trans Inc	10	2.6
Other Locations	39	9.5	Other Locations	20	5.2
Total	378		Total	386	

The table reports the 10 most common delivery locations for EOL gas and electricity wash trades completed during choice markets between January 2000 and November 2001. The label "Financial" is used for any wash trades in which a delivery point was not specified.

Table VII-7 reports the individual trading days with the most wash trades in a single product and involving a single counterparty. The heaviest wash trading of gas products occurred on March 26, 2001, when Entergy-Koch Trading, LP completed 12 pairs of wash trades in the next-day contract for physical delivery at Henry Hub. The details of this series of wash trades are provided as an example in Table VII-8, which focuses on a series of 24 trades that occurred in a 5-minute interval on March 26, 2001. With respect to this occurrence, it is interesting that no counterparty other than Entergy-Koch Trading, LP completed any transactions in this EOL product within ±30 minutes of the wash trades. It is difficult to identify any legitimate business reason why Entergy-Koch Trading, LP would need to complete 12 buys and 12 offsetting sells in the same gas product in a period of less than 10 minutes, especially when no other company made any EOL trades in this product and the price remained unchanged. Our analysis also revealed that the trades were executed by three separate Entergy-Koch Trading, LP traders. One of the three Entergy-Koch Trading, LP traders always acted as the buyer or seller in every pair of wash trades, but never completed both sides of the transaction. The other two traders took turns completing the opposite side of each wash transaction. This suggests that the first trader may have recruited other

Entergy-Koch Trading, LP traders to participate in these wash trades in an effort to avoid detection. Finally, it is interesting to note that every wash trade pair occurred within 5 seconds of each other, while two pairs actually occurred simultaneously. The coordinated nature of the transactions leaves no doubt as to the prearranged nature of these wash trades.

Table VII-7. Days In Which Individual Counterparties Conducted the Most Wash Trades During Choice Markets

Gas Trades			
Counterparty	Wash Trade Pairs	Date	Product
Entergy-Koch Trading, LP	12	26-Mar-01	US Gas Phy HeHub 28Mar01
Entergy-Koch Trading, LP	7	24-Aug-01	US Gas Phy HeHub 25-27Aug01
ENA - IM West	4	30-Aug-00	US Gas Phy Index IF EP Perm Nov00-Mar01
Reliant Energy Services, Inc.	4	7-Dec-00	US Gas Phy EPNG SoCal Topk 08Dec00
Reliant Energy Services, Inc.	4	8-Dec-00	US Gas Phy EPNG SoCal Topk 09-11Dec00
Calpine Energy Services, L.P.	3	27-Sep-01	US Gas Swap Nymex Jan-Dec02
Coral Energy Holding, L.P.	3	5-Oct-01	US Gas Swap Nymex Nov01
Entergy-Koch Trading, LP	3	20-Jul-01	US Gas Phy HeHub 21-23Jul01
Entergy-Koch Trading, LP	3	27-Jul-01	US Gas Phy HeHub 28-30Jul01
Entergy-Koch Trading, LP	3	5-Sep-01	US Gas Phy HeHub 06Sep01
Power Trades			
Counterparty	Wash Trade Pairs	Date	Product
Aquila Energy Marketing Corporation	48	6-Oct-00	US Pwr Phy Firm Mid-C Peak Dec00
Aquila Energy Marketing Corporation	45	6-Oct-00	US Pwr Phy Firm COB N/S Peak Nov00
Dynegy UK Limited	4	14-Aug-01	US Pwr Phy Firm Mid-C Peak 15Aug01
Idaho Power Company, dba IDACORP Energy	3	28-Jul-00	US Pwr Phy Firm PALVE Peak Oct00
Idaho Power Company, dba IDACORP Energy	3	6-Nov-01	US Pwr Fin Swap ISO NE HE11-23 EPT 06Nov01

The table reports the days with the most frequent wash trading with a single counterparty and in a single product.

Table VII-8. Example of a Wash Trade Sequence for Trades Between EOL and Entergy-Koch Trading, LP

Trade Time	Wash Trade Pairs	EOL Buy or Sell
11:53:13	1	Sell
11:53:14	1	Buy
11:53:39	2	Sell
11:53:39	2	Buy
11:54:33	3	Sell
11:54:33	3	Buy
11:55:11	4	Sell
11:55:13	4	Buy
11:55:27	5	Buy
11:55:28	5	Sell
11:55:38	6	Sell
11:55:41	6	Buy
11:55:53	7	Sell
11:55:57	7	Buy
11:56:17	8	Sell
11:56:18	8	Buy
11:56:32	9	Buy
11:56:37	9	Sell
11:57:00	10	Buy
11:57:02	10	Sell
11:57:17	11	Sell
11:57:20	11	Buy
11:57:38	12	Buy
11:57:39	12	Sell

The table reports a series of trades occurring on EOL on March 28, 2001. Each trade is for physical delivery of gas at Henry Hub on March 28, 2001, and each was completed at a price of $5.235.

The heaviest wash trading in power products, and the most blatant overall wash trading event, occurred on October 6, 2000, when a trader for Aquila Energy Marketing Corporation (Aquila) completed 48 wash trades for December 2000 power delivery at Mid-Columbia and 45 wash trades for November 2000 power delivery at the California-Oregon Border. As mentioned in our Initial Report, an Enron trader attributed this trading activity to the fact that Aquila's trader was participating in a promotional campaign run by Enron. In an effort to promote the use of its EOL platform, Enron offered a prize to the trader with the highest volume of trades. In response to this campaign, the Aquila trader attempted to benefit personally by recording the largest volume of trades. An Enron trader verified that choice markets were created at both locations, which enabled Aquila's trader to complete these trades at no cost. Through this 40-minute series of 93 wash trades, the counterparty trader won and was awarded a big-screen television as the prize. The combined volume of trades involved in this incident was approximately 1.6 million MWh at a total value of $180 million, but at a net cost of $0. It is not known to what extent these data may have been reported in market indices or financial statements.

The above transactions by Entergy-Koch Trading, LP and Aquila both appear to have occurred at or near prevailing market prices. However, even a few wash trades at any price other than the average index price could have a substantial, manipulative effect on prices because the index would be skewed in the direction of the wash trades. The impact would be even more profound if the trades occurred at an illiquid location or if a larger number of wash trades occurred. In addition, creating the illusion of liquidity could distort markets, increase prices, and hurt customers.

Affiliate Price Manipulation

In many contexts, the definition of a wash trade has been limited to pairs of trades occurring simultaneously and at exactly the same price. Despite the occasional existence of choice markets, the EOL platform is normally characterized by a positive bid-ask spread, in which the ask (or offer) quote exceeds the bid quote. In this case, simultaneous buy and sell orders would be completed at slightly different prices. In order to determine the frequency of divergently priced wash trades, Staff analyzed data based on the criteria that both legs of the wash trade involved the same product, the same volume, and the same counterparty and occurred within 2 minutes of each other; however, Staff did not require prices to be identical or to occur during a choice market. Staff's analysis identified numerous apparent wash trades at divergent prices between Enron and other nonaffiliated companies, but we were most concerned with trades that occurred between Enron and its affiliates. In fact, as the owner of EOL, Enron had the ability to act as both buyer and seller on a given transaction and use a series of buys and sells with a net cost of zero to manipulate the market. As part of our analysis, Staff identified suspicious trading activity for off-peak delivery of power at Palo Verde for the month of January 2002 (see Table VII-9).

All trades in this sequence involved EPMI Long Term Southwest (an Enron affiliate) trading on EOL and occurred on August 14, 2001, over a 5-minute period. At 16:59:49 EPMI sold on EOL at a price of $18. Four seconds later EPMI purchased on EOL at a price of $40. At 17:02:22 EPMI sold on EOL at a price of $15, before purchasing 3 seconds later at a price of $25. Thirty-three seconds later EPMI sold on EOL at $25, and 13 seconds after that EPMI purchased on EOL at $15. At 17:03:46 EPMI sold at $40, and at 17:04:30 the sequence was completed with EPMI purchasing on EOL at $18. Note that the entire sequence of trades examined here is zero-sum. Therefore, collectively, these trades "washed." The average price of the sequence was $24.50.

Possible reasons for entering into these trades would be to give the impression of volatility or to affect average prices reported through market indices. In either event, affiliate trades completed at prices different from the true market would involve no net gain or loss to Enron as a whole. Under no circumstances can we comprehend any legitimate business reason to enter into such a string of transactions. The fact that these trades have a zero-sum gain to both parties also demonstrates how the price (or volume) of a transaction could be varied to make a wash trading effort less obvious, which may have been the case in this instance. Based on our analysis, we conclude that this activity was for no other reason than as a self-serving experiment to create volatility and manipulate industry data.

Table VII-9. Affiliate Trading Between EOL and Enron Affiliate EPMI Long Term Southwest

Time	Wash Trade Pairs	EOL Buy	EOL Sell
16:59:49	1	$18	
16:59:53	1		$40
17:02:22	2	$15	
17:02:25	2		$25
17:02:58	3	$25	
17:03:11	3		$15
17:03:46	4	$40	
17:04:30	4		$18
Average Price		$24.50	$24.50

The table reports August 14, 2001 power trades for off-peak physical delivery of power at Palo Verde during January 2002.

One-to-Many Versus Many-to-Many Trading Platforms

The design of EOL alone greatly lends itself to trading abuses and gave Enron unprecedented influence over energy markets. Using choice markets, wash trading, and other strategies, EOL's one-to-many trading platform (in which EOL was the counterparty on every trade) enabled Enron to send false signals, including volume and pricing, to the marketplace. Because the platform was operated entirely under Enron's discretion, Enron was able to present or influence the market in any way it wished. Specifically, Enron used its wash trading activities to deceive EOL users by giving the impression of a much deeper and more developed market, thus increasing the industry's faith in EOL. Overall, these false signals increased Enron's ability to unilaterally manipulate industry data and price indices under EOL's guise as a legitimate exchange measuring real market activity.

On the other hand, exchanges designed using a many-to-many platform better reflect legitimate bargaining between a willing buyer

and seller and have the transparency necessary to instill confidence in the market. Staff believes the industry has already recognized the inherent advantages of many-to-many platforms over one-to-many platforms, resulting in the IntercontinentalExchange (ICE) becoming an industry leader. However, even these platforms are not immune to manipulation. In Chapter IX, Staff identifies circumstances on many-to-many platforms in which companies use the creditworthiness of counterparties to restrict trading activity to a single counterparty only. This enables two counterparties to complete prearranged wash trades over a many-to-many platform because only the counterparty they designate as having a sufficient level of credit would have the ability to qualify as an acceptable counterparty and complete the trade at the specific bid or offer price.

Summary and Conclusions Regarding Wash Trades on EnronOnline

The Trade Press has reported that, like a casino, Enron had the "house" advantage by trading on EOL in energy markets. Based on our analysis of the archived EOL database, Staff concludes that this is a flawed analogy. For example, a card game in a casino has set rules and all players can clearly see who they are competing against. On EOL, Enron had access to trading histories, limit orders, and volumes of trades, and therefore understood the liquidity of the market. In contrast, an unaffiliated trader on EOL was only able to see the activity that was posted electronically on the EOL screen. More significantly, when bid and ask prices were changed, the trader was unable to know if it was due to a legitimate trade or if prices were being manipulated. Unlike a casino game, this lack of transparency prevented the trader from knowing with whom he was competing. Moreover, because the EOL platform was wholly controlled by Enron, there were no fixed rules. The EOL operator had an infinite ability to manipulate what was posted in any of the ways described above. Simply put, the use of EOL enabled Enron to post any price it wanted.

Staff concludes that wash trading was commonplace on the EOL trading platform between January 2000 and November 2001, and was more prevalent in the later months of this period. The wash trades considered here were identified by statistical criteria. Although it is unlikely that every pair of trades identified here meets the criteria of being prearranged and involving no economic risk, the overall evidence (including the use of choice markets, the volume of actual and apparent wash trades, and the existence of affiliate wash trades) supports the conclusion that trading abuses and market manipulation occurred on EOL.

The Enron market maker may have taken positions that favored higher or lower prices. As such, we do not know whether the wash trades pushed gas or electric prices higher or lower.

Recommendations

Staff recommends that future trading platforms be designed to provide a sufficient level of transparency to enable users to understand the movements of the market. This transparency includes the disclosure of specific bids and offers and associated volumes for each product. Staff discourages any exchanges or trading platforms from being managed by any market participant, or combination thereof, in order to avoid the inevitable conflict of interest between the roles of brokers and traders. Finally, Staff recommends that the Commission establish specific rules banning any form of prearranged wash trading activities and prohibiting the reporting of any affiliate trading activities through industry indices. Strict adherence to these rules should be a condition of market-based rate or gas certificate authority.

Staff also recommends that the Commission condition blanket gas certificates, as well as electric power market-based rates, to require that sellers who use trading platforms use only those trading platforms that employ a "credit change monitor" that would be used to help evaluate unusual patterns in credit changes in the platform. The reason for this requirement is that the credit structure could be used to manipulate access to other traders and, therefore, the perceived market pricing. In addition, the Commission should disallow market-based rates for public utilities that use trading platforms unless the owners or operators of those platforms agree to provide the Commission Staff with full access to trade reporting and order book information for the trading systems.

Given the relative ease with which EOL manipulated the market and deceived its users, we do not believe a one-to-many trading platform is acceptable. We recognize that electronic trading on the EOL platform offered many advantages over historical voice trading. Even with its disadvantages, traders embraced EOL because it was faster, more convenient, and gave a widely accepted point of reference. A combination of our analysis and the further evolution of many-to-many platforms and their inherent advantages over EOL should render the one-to-many platform obsolete. Finally, we note that UBS Warburg, which now operates the EOL platform, suspended its use on December 10, 2002, due to a lack of trade volume. In any event, Staff recommends that market-based rates and gas certificate authority be conditioned on sellers not using their own one-to-many platform.

Further, Staff recommends that Congress consider giving direct authority to a Federal agency to ensure that electronic trading platforms for wholesale sales of electric energy and natural gas in interstate commerce are monitored and provide market information that is necessary for price discovery in competitive energy markets.

VIII. The Profitability of EnronOnline Information Advantage

Staff, with assistance from Hendrik Bessembinder, Blaine Huntsman Chair in Finance, Eccles Business School, University of Utah, analyzed the profits earned by EnronOnline (EOL) market makers in five key product categories. As noted previously in this Report, the EOL platform was characterized by a one-to-many structure in which Enron was the counterparty to all customer trades. The EOL platform was quite successful for a period of time, attracting a substantial portion of overall trading in gas and power products. A question that arises is whether Enron was able to use its position as a market maker and counterparty to a substantial portion of industry trading activity to create monopoly profits for itself, at the expense of its trading partners.

The answer to this question is of interest in terms of understanding how energy trading, and the trading of commodities and financial products in general, should optimally be structured. The one-to-many structure used by EOL is relatively rare. Most markets for energy products, including TradeSpark and the IntercontinentalExchange (ICE), are structured on a many-to-many basis. At ICE, disparate traders transact directly with each other and the role of the exchange is mainly limited to disseminating quotations and facilitating trade processing. However, other situations arise in which a single intermediary acts as the counterparty to a substantial portion of customer trades. For example, a New York Stock Exchange (NYSE) specialist may interact with the majority of customer orders in the case of thinly traded stocks. In this case, however, a specialist is subject to substantial affirmative obligations and oversight by the NYSE to ensure that the monopoly position is not used to earn unusual profits at the expense of customers. EOL market makers were subject to no such regulations.

EOL market makers may have been able to earn monopoly profits by either of two complementary methods. First, they could have maintained wide bid-ask spreads. Second, they could have exploited the information advantage gained from seeing all customers' orders and trades (while each customer saw only their own orders and trades) to speculate profitably. Any speculative profit accruing to Enron would have been earned at the expense of its counterparties.

Measuring Trading Profits

Consider a market maker who hypothetically begins a trading session with no cash and no inventory. Each purchase by the market maker expends cash but adds to inventory, while each market maker sale adds to cash but deletes inventory. Since market-maker purchases do not need to equate to market-maker sales over any given time interval, the accumulated market-making profit after t periods is measured not by the accumulated cash balance, but by the sum of cash accumulated and the value of inventory, as:

$$\Pi_t = C_t + I_t V_t$$

where C_t is the cash balance, I_t is inventory in physical units ($I_t > 0$ implying that the market maker has accumulated the product and $I_t < 0$ implying that the market maker has a net obligation to deliver the product), and V_t is the market value per unit of inventory. To measure inventory gains requires an assessment of the fair market value per unit of inventory, V_t. The approach used here is to rely on the final EOL trade price as a proxy for market value at the end of trading period t in each contract.[1]

This measure of total market-making profit can be restated in a more useful way. Let B_t and S_t denote the quantity bought and the quantity sold, respectively, by the market maker from the start of trading until time t. The lesser of B_t and S_t represents the amount of customer buy (or sell) orders that can be paired or matched with corresponding sell (or buy) orders, while the difference between B_t and S_t is the unmatched order flow that becomes the market maker's net inventory, I_t, i.e., either increases or decreases in inventory. For example, if B_t = 70 and S_t = 50, the lesser of B_t and S_t, or $\min(B_t,S_t)$ = 50, and I_t = 20. Let P_B denote the average price for market-maker purchases and let P_S denote the average price for market-maker sales.[2] The market maker's trading profit can be measured as:

$$TP_t = (\min(B_t,S_t)) \times (P_S - P_B).$$

The market maker earns a trading profit if the average selling price exceeds the average purchase price. This price differential will reflect,

[1]Using the final trade price as a proxy for fair market value introduces some measurement error. The final trade may occur at either the ask or the bid, while fair value presumably lies between the bid and the ask quotes. However, this measurement error is likely to average to nearly zero across the many individual products studied.

[2]Each price is computed as the volume-weighted average across trades.

but is not limited to, the bid-ask spread. It will also include speculative profits if the market maker is able to attract customer buy orders prior to price declines and customer sell orders prior to price increases. Trading profits depend on the excess of the average sell price over the average buy price and on the quantity of matched order flow, i.e., the lesser of B_t and S_t. In addition to this trading profit, total market-making profit will reflect gains and losses on the net order imbalances (i.e., inventory). If purchases exceed sales (i.e., inventory is positive), the inventory gain as of period t can be measured as:

$$IG_t = (B_t - S_t) \times (V_t - P_E).$$

This reflects that the market maker gains from a long inventory position if the inventory is worth more than his average acquisition price. In cases where sales exceed purchases so that the market maker is net short, the inventory gain can be computed as:

$$IG_t = (S_t - B_t) \times (P_S - V_t),$$

reflecting that a market maker gains on a short inventory position if the market value falls below his average sales price. Total market-making profit can then be measured as the sum of trading profits and inventory gains:[3]

$$\Pi_t = TP_t + IG_t.$$

This study estimates EOL market-making profits for five important energy product categories: power trades for physical delivery at the California-Oregon Border (COB); power trades for physical delivery at Palo Verde, Arizona; natural gas trades for physical delivery at Topock, California; natural gas trades for physical delivery at Henry Hub, Louisiana; and trades in the New York Mercantile Exchange (NYMEX) look-alike swap, which is a financial contract that mimics the NYMEX Henry Hub futures contract. The data cover the period January 1, 2000 to December 31, 2001.

Profits are measured for each individual product in these categories from the time of the first trade in the product until the last trade. An individual product is distinguished by the product to be delivered, the period during which delivery is to take place, and the firmness of the obligation to deliver. For example, a "next-day" contract to deliver gas at Topock on September 27, 2001 would be evaluated separately from a "rest-of-month" contract to deliver gas on all remaining days during

[3]It can be verified that market-making profits measured as the sum of trading profits and inventory gain are algebraically identical to profits measured as the sum of cash balance and inventory value.

September 2001. Trading profits are measured based on balanced trades (the minimum of EOL purchases and sales) from the first trade until the final trade in each individual product. Inventory profits are measured by comparing the average inventory acquisition price with the final EOL price for the product. Trading profits and inventory gains are then summed across all products within a category.[4]

To demonstrate the calculation of market-making profit for a specific product, consider the contract for delivery of Topock gas on February 28, 2001. This contract traded 44 times, all on February 27, 2001. Enron recorded purchases (B_t) of 195,000 MMBtu and sales (S_t) of 210,000 MMBtu. Enron's average purchase price (P_b) was $12.1795, while its average sales price (P_s) was $12.7976. The final trade in the product on EOL (V_t) was at a price of $12.75. The lesser of purchases or sales, representing matched order flow, is calculated as $\min(B_t,S_t)$ and equals 195,000 MMBtu. Net inventory is calculated by the equation $S_t - B_t$ and represents a short position (sales exceeded purchases) of 15,000 MMBtu.

Using the equation $TP_t = (\min(B_t,S_t)) \times (P_S - P_B)$, trading gains are $195,000 \times (12.7976 - 12.1795) = \$120,530$. Meanwhile, using the equation $IG_t = (S_t - B_t) \times (P_S - V_t)$, inventory gains are $15,000 \times (12.7976 - 12.75) = \$714$. This reflects that in accumulating its short position, Enron sold at an average price (P_S) slightly above the final price (V_t) for the product. The reasoning is that the short position must be covered from somewhere, and the final price is an estimate of the cost of doing so. Therefore, using the equation $\Pi_t = TP_t + IG_t$, total market-making profit in the product defined as delivery of Topock gas on February 28, 2001 is $120,530 + $714 = $121,244.

[4] Physical purchases B_t, sales S_t, and inventory $I_t = B_t - S_t$ depend on both the contracted quantity and the delivery horizon. For gas products, this is the product of the number of MMBtu and the number of days for which delivery is required. For power contracts, this is the number of MWh times the number of delivery days times the number of delivery hours (8 for off-peak contracts and 16 for on-peak contracts).

EOL Market-Making Profits

Table VIII-1 reports market-making profits in the five product categories described above. EOL market making was highly profitable in aggregate. Across the five product categories and the 2 years of data, trading profits exceeded $641 million. Estimated inventory gains were negative $54 million, leaving $587 million in combined market-making profit. This equated to an average market-making profit of $1,200 for each of the 507,000 trades, or profits that were 0.08 percent of the $506.7 billion in trading activity.

The profitability of EOL market making varied dramatically across product categories. Trading of NYMEX look-alike swaps (financially settled swaps whose value is determined based on the settlement of NYMEX futures contracts) was immensely profitable, with trading gains exceeding $764 million and estimated gains on inventory amounting to another $156 million. This equates to a total market-making profit of $2,300 for each of the 400,000 EOL trades in NYMEX look-alike swaps.

In contrast to the profitability of this swap trading, EOL market makers took losses in the other four product categories. COB power contracts yielded a trading gain of $10.3 million, but this was more than offset by estimated inventory losses of $25.7 million. Market making in Palo Verde power, Topock gas, and Henry Hub gas led to both trading losses and estimated losses on inventory. Trading losses on Palo Verde power contracts exceeded $128 million, while trading losses in Topock gas and Henry Hub gas were more moderate, amounting to $0.9 million and $3.8 million, respectively. Estimated inventory losses for Palo Verde power were also large, at $168 million, while inventory losses for Topock and Henry Hub gas were estimated at $14 million and $2 million, respectively.

Finding trading losses for these physical delivery contracts is surprising. EOL market makers generally charged a positive bid-ask spread, which provided positive trading profits, other things being equal. Measured trading profits were negative for all physical delivery products except COB power. This implies that the average price at which EOL sold was less than the average price at which EOL purchased.

Finding the average EOL selling price to be less than the average EOL purchase price is surprising, considering that a positive bid-ask spread

was charged. The following example illustrates how this occurred. Suppose that the EOL market maker initially posts an ask (willing to sell) quote of $3.02 and a bid (willing to buy) quote of $3.00. A customer buys (EOL sells) at the ask quote of $3.02. Shortly thereafter, the EOL market maker elects (perhaps after learning of bullish fundamental information) to update his quotes to $3.06 ask and $3.04 bid. A customer then sells at the $3.04 bid price, leaving EOL with a trading loss of $.02 in the matched pair of trades comprising this example. The key feature of this example is the upward movement of quotes after the customer purchase. The trading losses observed in this study for the Palo Verde, Topock, and Henry Hub products imply that adverse (to EOL) price changes between trades occurred systematically and more than offset the positive bid-ask spread.

The negative estimates of inventory gain for the four physical delivery product categories imply that the EOL market maker tended to accumulate inventory at prices that exceed the eventual, final EOL price and tended to enter short inventory positions at prices below the eventual, final EOL price. These results with respect to both trading losses and inventory losses are the opposite of what would be expected if the EOL market maker were able to extract useful information from an observation of customer orders and trades.

There are at least three possible explanations for the results observed here. One possibility is that EOL market makers, with the exception of the market maker in the NYMEX look-alike swap, were not as skilled at trading as their customers and thus were unable to earn trading profits despite the advantages of a positive bid-ask spread and superior information about customers' orders and trades. However, this explanation does not seem plausible. A second possibility is that the EOL market makers in the physical delivery products were skilled and able to exploit their information advantage, but executed their most profitable trades on platforms other than EOL. This also seems highly unlikely. A third possibility is that EOL market makers used the information obtained from observing customers' orders and trades in the physical markets not to trade profitably in those markets, but to trade profitably in various financial markets (futures, options, swaps, etc.) whose prices depend on fundamental factors in the physical markets. The large profits observed for the financial NYMEX look-alike swap are certainly consistent with this reasoning. It is also consistent with the manipulation strategies of the physical markets to profit in the financial markets (an issue described elsewhere in this Report).

Tables VIII-2 through VIII-6 provide more detail on market-making profits in the individual categories, including profits by calendar

month and profits on short-term (delivery horizon of 3 days or less), medium-term (delivery horizon between 4 and 31 days), and long-term (delivery on more than 31 days) contracts. A few results are notable. First, trading profits are highly variable over time. NYMEX look-alike swaps provide the most dramatic example. Trading profit exceeded $270 million in October 2001 (although this was dwarfed by an estimated inventory loss of $808 million during the same month). Trading losses of $270 million were incurred in December 2000, followed by trading gains of $166 million in January 2001. Similar variation on a smaller scale is observed in other markets. For example, COB power trading yielded profits of $30 million in January 2001 and losses of $19 million in May 2001. This type of variation in trading gains demonstrates that EOL market makers were active (and sometimes unsuccessful) speculators, not passive market makers earning a living from the bid-ask spread. This, in turn, exacerbates concerns that the market maker in a one-to-many platform could use the information in orders and trades to the detriment of customers.

Conclusions

The EOL platform had a large market share for trading energy products and was characterized by a one-to-many structure that allowed the EOL market maker to see all customer orders and trades, while each customer saw only its own orders and trades. These considerations lead to the possibility that the EOL market maker possessed a degree of monopoly power and would be able to earn monopoly profits at the expense of its customers.

This chapter reports on market-making profits in five important energy product categories, including physical power for delivery at COB and Palo Verde, physical gas for delivery at Henry Hub and Topock, and financial swaps based on the NYMEX Henry Hub contract. In aggregate, EOL earned market-making profits in excess of $587 million during 2000 and 2001 for these five product categories. The magnitude and time series variability of these profits suggest that EOL market makers did not simply act as passive suppliers of liquidity, i.e., one who stands ready to buy or sell and earn a moderate but steady profit from the bid-ask spread. Rather, EOL market makers were active and, on average, successful speculators. Somewhat surprisingly, market-making profits were concentrated in the only financial contract studied; EOL market makers actually sustained losses in the four physical delivery contracts examined. This result is consistent with the reasoning that EOL market makers used the information advantage gained from their central position in physical markets not to trade profitably in those markets, but to earn speculative profits in associated financial markets (futures, options, swaps, etc.).

This analysis highlights the importance of structuring markets to create effective competition for customer orders. A one-to-many format with an unregulated and unconstrained market maker is unlikely to lead to efficient outcomes. Many markets around the world are changing to a many-to-many format in which customers interact directly with each other. In a many-to-many format, customer limit orders compete to win customer market orders. Alternately, competitive market outcomes might be attained by having numerous potential market makers compete for order flow, as on the Nasdaq Stock Market and in the brokered "upstairs markets" that often accompany formal exchanges. In the few situations where a one-to-many structure is still observed (for example, in thinly traded NYSE stocks where the specialist participates in most trades), the specialist is subject to numerous affirmative obligations to protect customers and to oversight by the Exchange. To summarize, efficient market structures require either vigorous competition among potential suppliers of liquidity or oversight of the designated liquidity supplier.

Recommendation

Staff recommends that the Commission condition market-based rates and blanket gas certificates to require that sellers who use electronic platforms use only those platforms that agree to provide the Commission with full access to trade and order book information and agree to appropriate monitoring requirements.

Table VIII-1. Profits to Enron From EOL Market Making in Five Key Products

Product	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
COB Power Physical	10.3	-25.7	-15.4	-3.0	-0.58	2,637.5	5,099
Palo Verde Power Physical	-128.8	-168.5	-297.3	-11.4	-1.81	16,460.8	26,164
Topock Gas Physical	-0.9	-13.7	-14.6	-0.7	-0.42	3,496.3	21,928
Henry Hub Gas Physical	-3.8	-2.0	-5.8	-0.1	-0.09	6,606.1	52,828
NYMEX Gas Look-Alike Swaps	764.5	155.7	920.2	2.3	0.13	710,836.0	400,663
Total of Five Products	641.3	-54.2	587.1	1.2	0.08	740,036.9	506,682

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. The interval studied is January 2000 to December 2001.

Table VIII-2. Profits to Enron From EOL Market Making: Trades for Physical Delivery of Power at the California-Oregon Border

	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
All Trades	10.3	-25.7	-15.4	-3.0	-0.58	2,637.5	5,099
By Contract Term							
Long Term	-10.9	-3.7	-14.6	-42.7	-1.13	1,292.2	342
Medium Term	20.6	-20.6	0.0	0.0	0.00	1,127.5	959
Short Term	0.5	-1.4	-0.8	-0.2	-0.39	217.8	3,798
By Calendar Month							
January 2000	0.0	0.0	0.0	-0.2	-0.19	2.3	18
February 2000	0.2	-0.2	-0.1	-0.3	-0.08	109.8	272
March 2000	-0.6	-0.7	-1.3	-6.9	-1.44	92.1	193
April 2000	0.4	-0.1	0.3	1.3	0.45	61.8	219
May 2000	4.0	-16.7	-12.8	-133.3	-18.23	70.2	96
June 2000	-4.2	-6.8	-11.0	-123.6	-19.19	57.3	89
July 2000	-2.9	-8.9	-11.9	-54.4	-11.35	104.5	218
August 2000	-4.1	0.4	-3.7	-13.1	-0.83	448.3	284
September 2000	-0.3	-0.5	-0.8	-2.9	-0.35	230.3	275
October 2000	-1.6	-1.6	-3.2	-6.0	-1.01	314.6	529
November 2000	3.5	11.2	14.7	42.6	5.72	257.5	348
December 2000	3.5	-12.8	-9.3	-174.8	-21.07	44.0	53
January 2001	29.7	-68.6	-39.0	-299.9	-29.86	130.6	130
February 2001	1.0	4.5	5.5	44.2	6.90	80.1	125
March 2001	-1.8	-7.8	-9.6	-42.1	-3.59	266.7	227
April 2001	0.0	0.6	0.6	3.0	1.15	51.6	198
May 2001	-18.9	66.1	47.2	186.6	32.06	147.2	253
June 2001	13.7	-0.5	13.2	54.4	25.59	51.4	242
July 2001	-7.8	12.4	4.6	14.3	13.87	33.2	321
August 2001	-2.6	2.3	-0.3	-1.0	-2.17	15.5	336
September 2001	-1.2	2.5	1.3	4.1	7.70	16.9	317
October 2001	0.0	-0.6	-0.6	-2.4	-5.35	10.8	244
November 2001	0.5	0.2	0.7	6.1	1.65	42.9	116
December 2001	0	0	0	0	0	0	0

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. Short-term contracts involve delivery periods of 3 days or less. Medium-term contracts involve delivery periods of 4 to 31 days. Long-term contracts involve delivery periods over 31 days.

Table VIII-3. Profits to Enron From EOL Market Making: Trades for Physical Delivery of Power at Palo Verde, Arizona

	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
All Trades	-128.8	-168.5	-297.3	-11.4	-1.81	16,460.8	26,164
By Contract Term							
Long Term	-55.7	-100.0	-155.7	-75.3	-2.13	7,293.9	2,069
Medium Term	-74.3	-60.5	-134.8	-17.1	-1.59	8,502.7	7,896
Short Term	1.2	-8.0	-6.8	-0.4	-1.03	664.1	16,199
By Calendar Month							
January 2000	0.0	0.0	0.0	-0.1	-0.07	3.8	25
February 2000	0.3	-1.1	-0.9	-2.1	-0.60	141.6	411
March 2000	-0.8	-0.9	-1.8	-3.9	-0.97	180.7	446
April 2000	0.5	3.3	3.8	8.9	1.49	253.8	426
May 2000	-0.9	36.0	35.1	155.9	18.35	191.1	225
June 2000	33.8	3.2	36.9	95.4	6.81	542.0	387
July 2000	0.0	13.3	13.4	26.1	3.27	408.6	511
August 2000	-13.4	-34.4	-47.8	-60.3	-4.12	1,159.1	793
September 2000	16.8	4.7	21.5	25.9	2.61	822.6	828
October 2000	-8.2	0.7	-7.5	-6.6	-1.06	712.5	1,137
November 2000	24.7	-77.1	-52.4	-37.9	-5.40	969.8	1,382
December 2000	10.2	-290.0	-279.8	-690.7	-94.36	296.4	405
January 2001	13.7	263.9	277.6	488.8	35.89	773.6	568
February 2001	-115.5	91.2	-24.3	-42.9	-2.45	990.3	566
March 2001	39.3	58.3	97.6	97.0	7.49	1,302.7	1,006
April 2001	36.7	-158.1	-121.4	-83.9	-6.78	1,789.5	1,446
May 2001	-27.2	-90.0	-117.3	-72.0	-6.29	1,863.6	1,628
June 2001	-93.9	34.1	-59.7	-27.2	-4.24	1,408.4	2,198
July 2001	0.5	-61.3	-60.8	-31.6	-12.62	481.9	1,921
August 2001	-11.6	5.2	-6.4	-2.1	-0.99	648.4	3,021
September 2001	-19.4	15.0	-4.4	-2.0	-1.32	332.4	2,217
October 2001	-4.6	-12.9	-17.4	-6.1	-3.45	505.8	2,865
November 2001	-9.9	28.6	18.7	10.7	2.74	682.1	1,752
December 2001	0	0	0	0	0	0	0

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. Short-term contracts involve delivery periods of 3 days or less. Medium-term contracts involve delivery periods of 4 to 31 days. Long-term contracts involve delivery periods over 31 days.

Table VIII-4. Profits to Enron From EOL Market Making: Trades for Physical Delivery of Gas at Topock, California

	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
All Trades	-0.9	-13.7	-14.6	-0.7	-0.42	3,496.3	21,928
By Contract Term							
Long Term	0	0	0	0	0	0	0
Medium Term	2.1	-6.6	-4.5	-3.8	-0.40	1,115.8	1,179
Short Term	-3.0	-7.2	-10.2	-0.5	-0.43	2,380.5	20,749
By Calendar Month							
January 2000	0	0	0	0	0	0	0
February 2000	0.0	0.0	0.0	0.0	0.09	3.7	199
March 2000	0.0	0.0	0.0	0.0	-0.12	10.8	497
April 2000	0.0	0.0	0.0	0.0	-0.10	10.3	445
May 2000	0.0	-0.1	-0.1	-0.1	-0.10	62.8	1,129
June 2000	0.0	0.0	-0.1	0.0	-0.07	74.9	1,305
July 2000	0.0	0.0	0.0	0.0	-0.03	67.7	1,145
August 2000	-0.6	0.5	-0.1	-0.1	-0.09	162.1	1,236
September 2000	0.0	0.0	0.0	0.0	0.02	127.5	1,222
October 2000	-2.3	0.7	-1.6	-1.4	-0.73	224.5	1,156
November 2000	-2.1	-3.3	-5.3	-3.1	-1.34	398.9	1,703
December 2000	2.6	-5.8	-3.2	-1.3	-0.35	902.4	2,434
January 2001	0.2	-2.4	-2.2	-1.3	-0.69	314.2	1,623
February 2001	3.0	-0.1	2.9	1.9	0.66	440.3	1,557
March 2001	0.0	-1.9	-1.9	-6.4	-2.46	76.6	296
April 2001	-0.6	-0.2	-0.8	-1.0	-0.45	184.9	865
May 2001	0.1	1.0	1.1	1.2	0.78	138.1	921
June 2001	-0.7	0.2	-0.5	-0.4	-0.44	111.8	1,315
July 2001	-0.2	-1.0	-1.2	-1.4	-1.77	66.5	841
August 2001	-0.3	-1.2	-1.5	-1.9	-2.92	51.6	787
September 2001	0.0	0.0	0.0	-0.1	-0.17	25.8	577
October 2001	0.0	0.0	0.0	0.0	0.02	29.9	442
November 2001	0.0	0.0	0.0	-0.2	-0.33	11.3	233
December 2001	0	0	0	0	0	0	0

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. Short-term contracts involve delivery periods of 3 days or less. Medium-term contracts involve delivery periods of 4 to 31 days. Long-term contracts involve delivery periods over 31 days.

Table VIII-5. Profits to Enron From EOL Market Making: Trades for Physical Delivery of Gas at Henry Hub, Louisiana

	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
All Trades	-3.8	-2.0	-5.8	-0.1	-0.09	6,606.1	52,828
By Contract Term							
Long Term	0	0	0	0	0	0	0
Medium Term	-1.8	0.4	-1.5	-0.4	-0.08	1,819.5	3,524
Short Term	-1.9	-2.4	-4.3	-0.1	-0.09	4,786.6	49,304
By Calendar Month							
January 2000	0.0	0.0	0.0	0.0	-0.20	0.3	14
February 2000	0.0	-0.1	-0.1	-0.2	-0.53	13.0	328
March 2000	0.0	0.0	0.0	0.0	0.04	36.9	570
April 2000	0.0	-0.1	-0.1	-0.1	-0.15	48.4	750
May 2000	-0.1	-0.2	-0.2	-0.2	-0.12	209.4	1,050
June 2000	-0.4	0.0	-0.4	-0.2	-0.09	432.1	1,864
July 2000	-0.1	-0.1	-0.2	-0.2	-0.12	209.8	1,237
August 2000	0.1	-0.1	0.0	0.0	-0.01	309.5	1,546
September 2000	0.0	-0.2	-0.2	-0.1	-0.08	242.2	1,225
October 2000	-0.1	-0.2	-0.4	-0.2	-0.11	336.4	1,972
November 2000	-0.3	0.6	0.3	0.1	0.04	741.2	3,309
December 2000	-1.6	0.6	-1.0	-0.4	-0.20	474.3	2,327
January 2001	0.0	-0.6	-0.5	-0.2	-0.14	374.0	2,328
February 2001	0.3	-0.2	0.2	0.1	0.04	393.4	2,579
March 2001	-0.3	0.0	-0.3	-0.1	-0.07	414.5	3,386
April 2001	-0.2	-0.3	-0.5	-0.1	-0.13	394.6	3,477
May 2001	-0.2	-0.2	-0.4	-0.1	-0.10	396.7	3,540
June 2001	-0.5	-0.4	-0.9	-0.2	-0.17	568.7	4,579
July 2001	-0.1	0.0	-0.1	0.0	-0.04	290.6	3,855
August 2001	-0.5	-0.2	-0.7	-0.2	-0.26	267.8	3,625
September 2001	0.0	0.1	0.2	0.1	0.13	132.0	2,603
October 2001	0.2	-0.1	0.1	0.0	0.04	245.3	4,698
November 2001	-0.1	-0.3	-0.4	-0.2	-0.57	75.2	1,966
December 2001	0	0	0	0	0	0	0

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. Short-term contracts involve delivery periods of 3 days or less. Medium-term contracts involve delivery periods of 4 to 31 days. Long-term contracts involve delivery periods over 31 days.

Table VIII-6. Profits to Enron From EOL Market Making: Trades in NYMEX Look-Alike Swaps

	Trading Profit	Gain on Inventory	Total Profit	Profit per Trade	Profit as Percent of Trading	Total Dollars Transacted	Number of Trades
All Trades	764.5	155.7	920.2	2.3	0.13	710,836	400,663
By Contract Term							
Long Term	252.8	900.0	1152.8	14.0	0.39	294,442	82,220
Medium Term	511.7	-744.3	-232.6	-0.7	-0.06	416,394	318,443
Short Term	0	0	0	0	0	0	0
By Calendar Month							
January 2000	0.3	-0.3	0.1	0.4	0.05	175	195
February 2000	2.6	7.2	9.8	2.6	0.27	3,624	3,770
March 2000	-2.2	16.3	14.1	2.6	0.20	7,127	5,461
April 2000	4.6	11.8	16.4	3.2	0.24	6,696	5,166
May 2000	42.7	9.5	52.2	4.4	0.29	18,183	11,781
June 2000	12.6	-31.6	-19.0	-1.1	-0.07	28,197	17,750
July 2000	58.9	-54.4	4.5	0.4	0.03	17,044	12,315
August 2000	15.0	206.1	221.1	15.8	0.91	24,395	13,962
September 2000	45.6	43.8	89.4	7.0	0.33	26,913	12,852
October 2000	67.6	-257.3	-189.7	-12.6	-0.54	35,143	15,061
November 2000	-108.8	49.0	-59.8	-2.7	-0.11	53,859	22,453
December 2000	-269.9	120.0	-149.9	-7.7	-0.33	45,577	19,437
January 2001	165.6	-41.0	124.6	6.2	0.30	42,151	20,037
February 2001	120.5	-62.0	58.5	3.2	0.16	35,480	18,502
March 2001	46.9	-1.3	45.6	2.4	0.11	41,031	19,251
April 2001	18.9	28.4	47.3	2.4	0.12	39,821	19,466
May 2001	106.9	69.4	176.3	7.9	0.41	43,254	22,238
June 2001	1.2	150.6	151.8	5.7	0.33	46,339	26,413
July 2001	75.3	-61.9	13.3	0.5	0.03	39,619	26,231
August 2001	10.0	431.8	441.8	16.0	1.07	41,228	27,630
September 2001	32.1	217.6	249.7	12.4	0.91	27,391	20,124
October 2001	270.8	-807.8	-537.1	-15.1	-1.06	50,999	35,569
November 2001	40.2	57.9	98.1	3.9	0.27	36,933	24,954
December 2001	7.1	54.0	61.1	1744.9	104.67	58	35

Trading profit reflects the excess of the average Enron sell price over the average Enron buy price times the quantity of matched EOL trading. Gain on inventory reflects profits on the net EOL order imbalance, measured by the differential between the final EOL price for the contract and the average inventory acquisition price. Total profit is the sum of trading profit and gain on inventory. Total dollars transacted is the sum of total purchases and total sales on EOL. Profit as a percent of trading is total profit relative to total dollars transacted. Dollar amounts are in millions except for profit per trade, which is in thousands. Short-term contracts involve delivery periods of 3 days or less. Medium-term contracts involve delivery periods of 4 to 31 days. Long-term contracts involve delivery periods over 31 days.

IX. Enron's Manipulation of the Natural Gas Markets, Portions of the Enron Online Black Box Revealed, and Forward Looking Recommendations[1]

Background

Financial energy products are used to hedge risk on physical energy products, and the two are interrelated. Physical transaction prices dictate the pricing of financial products, i.e., financial products derive their value from the underlying physical market. The depth and liquidity of financial energy markets are far greater than those of physical markets.

The relationship between financial and physical energy products and the relatively thinner and less liquid physical markets provides opportunities to manipulate the physical markets and profit in the financial markets. This is true regardless of whether the manipulation in the physical market raises or lowers prices for the physical commodity.

This chapter analyzes an experiment to test a manipulation strategy and an actual manipulation by Enron using EnronOnline (EOL). Enron manipulated the price of physical gas upward, then downward. Although the price change in the physical markets was only about $0.10/MMBtu, Enron profited due to the effect that this small change in the physical price had on its large financial position. Enron earned more than $3 million from this manipulation.

FERC Staff obtained information indicating that Enron traders potentially manipulated the price of natural gas at the Henry Hub in Louisiana to profit from positions taken in the over-the-counter (OTC) financial derivatives markets (OTC markets). Through interviews, depositions, document review, and data analysis, Staff found substantial evidence corroborating the initial information.[2] It is Staff's opinion that Enron traders, through transactions falling within the Commission's jurisdiction and authorized through a blanket certificate,

[1]This section was prepared by FERC Staff with the assistance of outside consultant Chester Spatt, Mellon Bank Professor of Finance, Graduate School of Industrial Administration, Carnegie Mellon University.

[2]During the investigation into Enron and EnronOnline, FERC provided the Commodity Futures Trading Commission (CFTC) with access to the electronic databases that FERC Staff relied on to generate the analysis for this and other chapters of the Report. FERC provided the CFTC, Department of Justice (DOJ), and Securities and Exchange Commission (SEC) with a preliminary draft of this Report on March 3, 2003, asking for comments and concerns. FERC then met with the CFTC, DOJ, and SEC on March 10, 2003 to discuss this Report prior to its issuance.

successfully manipulated the physical natural gas markets. The manipulation yielded profits in the financial OTC markets.[3]

Staff reviewed documents disclosed by Enron describing the same strategy hypothetically in a memorandum predating the manipulation that Staff discovered.[4] This caused concerns that Enron traders executed this strategy at other times and in other locations. As part of its research into the market manipulation, Staff identified key elements relating to the execution of the market manipulation strategy. Using this information, Staff proceeded to search for additional occurrences of manipulations at other times and in other locations. Staff's search resulted in the discovery of trading behavior executed by Reliant that involved a different strategy but used similar techniques regarding the physical purchase of gas. As described in Chapter II, this trading behavior caused at least a portion of the increase in gas prices at the Southern California Border from December 2000 through February 2001. In the following sections, Staff describes the financial and physical gas markets, necessary conditions for manipulation, manipulation strategies, and an actual manipulation of Henry Hub prices by Enron traders.

The Relationship Between Natural Gas Financial Derivatives and the Underlying Physical Gas Contracts

General Purpose for Physical and Financial Natural Gas Markets

Natural gas traders and marketers in the United States use many different physical and financial natural gas products to absorb the risks associated with fluctuating natural gas prices. For example, traders can purchase gas each day in the spot markets or they can agree in advance

[3]Commission jurisdiction is pursuant to the Commission's authority under the Natural Gas Act (NGA) of 1938, particularly Sections 1(b), 4(a), and 5(a). The blanket certificate is provided in Parts 284.284 and 284.402 of this Commission's Regulations.

[4]The following excerpt is a hypothetical example extracted from an Enron document to which Enron waived privileges: "**Leveraged Trading** – Trading Company ("TC") is short fixed-price physical gas. TC is long financial *Gas Daily* through gas swap agreements. TC starts buying physical gas and goes beyond what is necessary to cover its short position; prices in the cash market increase and prices reported in *Gas Daily* are much higher. What are the legal issues? Are the risks greater if the swap reference price is the "average of the last three days of the month" or "average of all the days in a calendar month"?" Bates # EC001653170; "Discussion of Hypothetical Trading Strategies," January 3, 2001.

to purchase gas based on a daily index. Traders also can lock in an average gas price through monthly or longer term physical contracts. Alternatively, these fixed-price contracts can be replicated or achieved through the combined execution of physical index purchases, basis swaps, *Gas Daily* swaps, and NYMEX futures or swaps. Depending on whether the trader needs to buy or sell gas in the future, the trader would buy or sell the above products. Based on the risks the trader is most concerned about, the trader may enter some or all of these transaction types or the trader may choose to defer trading until prices become more favorable.

The availability of diverse types of instruments for bearing risk facilitates the allocation of risk to those best situated to bear these risks, increasing the efficiency of the capital market and lowering the cost of risk bearing. Financial services and energy firms that operate across the relevant markets are potentially willing to intermediate (transform) risks because of their own ability to hedge or offset the underlying exposure.

Importance of Liquidity in the Natural Gas Markets

Liquidity refers to the ability to sell an asset and convert it into cash, at a price close to its fundamental value, in a short period of time. Generally, liquid markets form when a large number of buyers and sellers trade substantial volumes of a product. In the natural gas marketplace, the "gold standard" instruments are the physical products traded for delivery at the Henry Hub location, where many pipelines converge near the supply region in Louisiana. In the financial markets, the most important instruments are the NYMEX futures contracts, which settle based on the price of physically delivered natural gas at the Henry Hub. The settlement of the monthly NYMEX futures is determined 3 days from the end of the prior month.[5] Because of the direct linkage between Henry Hub and important delivery points in the Northeast and Midwest, the Henry Hub physical market (relative to other physical markets) and the NYMEX futures market both tend to be relatively deep or liquid, thereby providing attractive instruments for many market participants. These instruments correlate reasonably with the hedging needs of many individual market participants. Consequently, although Henry Hub-related markets expose many individual participants to basis risk relative to gas price risk at other locations, the relative attractiveness of the Henry Hub to many of the market participants leads to a concentration of trading activity in Henry Hub-based physical and financial products.

[5]A NYMEX futures contract is based on the delivery of 10,000 MMBtu. See www.nymex.com.

The activity and depth on the NYMEX (next month) futures contract is much greater than that for the Henry Hub next-day physical contract because of the longer 1-month term associated with the contract, which reflects planned gas needs as opposed to marginal unanticipated changes to needs; the attractiveness of financial settlement; and the credit risk reduction associated with daily mark-to-market settlement.[6] The liquidity of the Henry Hub next-day physical market is greater than the liquidity of physical markets in other locations. Because of the differing liquidities in these markets, the price impact of trading positions of a given size in these instruments can be relatively less than for instruments traded in smaller, less active products. As in various market settings, liquidity is self-reinforcing because market participants have a strong incentive to trade using the deepest and most liquid markets. Trading activity attracts trading activity and liquidity concentrates at the deepest markets. Traders often use the NYMEX futures to hedge overall market conditions because of its liquidity.

Physical Transaction Values Dictate the Pricing of Financial Derivatives

Natural gas financial derivatives "derive" their value from transaction prices at major receipt and delivery points for natural gas. A significant variety of natural gas financial derivatives exist.

The most commonly traded natural gas financial derivative is the NYMEX futures contract, which derives its value from physical transactions occurring at Henry Hub in Louisiana.[7] The other primary financial derivatives are *Gas Daily* swaps and basis swaps, which are traded in the OTC markets. These products relate to the Henry Hub and many other locations in North America. The *Gas Daily* swap hedges the price risk between the price quoted in *Inside FERC* (whose settlement is determined by the average price for next-month gas at the specified location over the last 5 trading days for the current month) and the price quoted in the *Gas Daily* index. Basis swaps provide a hedge against relative price changes between two different locations (primarily the Henry Hub and another location), swapping the prices posted as the last-day NYMEX settlement price and the price quoted in *Inside FERC* for the location being hedged (adjusted by a market premium). One of the most common OTC derivative products is known as the "OTC swap," also known as the NYMEX look-alike

[6]Daily "mark-to-market" settlement is the daily cash flow system used by U.S. futures exchanges to maintain a minimum level of margin equity for a given futures or options contract position by calculating the gain or loss in each contract position resulting from changes in the price of the futures or options contracts at the end of the trading day. See www.nymex.com.

[7]The specific delivery location is the Sabine Pipe Line Co.'s Henry Hub in Louisiana. See www.nymex.com.

swap. This swap derives its value from the price of the NYMEX natural gas futures contract.

Henry Hub physical transactions strongly correlate with the NYMEX futures and the related OTC NYMEX look-alike swaps because the NYMEX futures directly settle based on the Henry Hub physical delivery price. The correlation between the NYMEX futures and next-day physical gas at Henry Hub is not perfect (although it is very high) because of various timing differences between the futures contract and the next-day physical contract. In particular, the futures contract represents delivery in the following month and the Henry Hub physical contract represents next-day delivery.[8] The volatility of Henry Hub should be greater to reflect the inherent volatility in the value of a next-day product (which reflects unanticipated demands) versus the volatility in a monthly futures contract (which reflects anticipated demand). This is reinforced by the mean reversion of commodity spot prices.

Many other financial derivative contracts relate in similar ways to underlying physical transactions of varying terms. The direct and indirect relationships between financial derivatives and physical transactions provide the linkage needed to exercise particular manipulation strategies. Generally, the dependence of financial derivative products on physical transaction values results in a strong correlation between changes in the value of the physical product and the financial derivatives. For example, if next-day physical gas (gas that will be delivered the next day) trades at a high level on a particular day, this affects the settlement of the portion of a *Gas Daily* financial swap that settles the next day. Looking forward, the increase in spot prices for gas indicates an increase in demand for gas (or a decrease in inventory) and may change expectations for prices of gas in the future as well. A change in expectations for future natural gas prices will affect the value of financial derivative transactions designed to settle on those future days. It is this interrelationship that provides an opportunity for manipulation.

[8]Delivery under NYMEX contracts shall take place no earlier than the first calendar day of the delivery month and shall be completed no later than the last calendar day of the delivery month. All deliveries shall be made at an hourly and daily rate of flow that is as uniform as possible over the course of the delivery month. See www.nymex.com.

Relative Differences in Liquidity Across Markets Combined With Correlated Values Between Those Markets Provides an Opportunity for Profitable Manipulation

Although there are strong inherent advantages to the diverse ways in which risks are packaged in the marketplace, the presence of alternative instruments reflecting similar risks generates a need for correct relative pricing to avoid the ability to generate arbitrage profits. Arbitrage profits are riskless profits generated by simultaneously selling an overpriced asset while purchasing an underpriced substantively equivalent asset.[9] For example, if two marketplaces existed for the same commodity and the first market offered to buy the commodity at $5.00 while the other market offered to sell the commodity at $4.00, an opportunity to simultaneously buy from the $4.00 market and sell to the $5.00 market would arise, yielding a $1.00 profit as long as prices remained the same. As traders take advantage of the arbitrage opportunity, buying pressure in the cheaper market and selling pressure in the expensive market brings the markets in line, resulting in correct relative prices. For similar, but not substantively identical products, these correct relative prices are also expected. However, any substantive differences in the products create some risk that variations may occur or persist.

The expectation that related products exhibit correct relative prices results in a strong correlation between prices. This creates the potential to manipulate the related products for a profit. This potential arises when, in the short run, transactions of the same size affect prices in the two markets differently. One factor that distinguishes between markets is relative liquidity. If a market involved a much larger daily transactional volume and a greater number of buyers and sellers relative to another market, the price impact of individual trades might be less in the first market. To take advantage of the different impact, a trader could first take a long (or short) position in the market with greater liquidity. A long position would rise in value as the relevant gas prices rise, while a short position would rise in value as those gas prices fall.[10] The trader could then attempt to increase (or decrease) the

[9]See *The Relative Pricing of High Yield Debt: The Case of RJR Nabisco Holdings Capital Corporation,"* R. Dammar, K. Dunn, and C. Spatt, American Economic Review, Vol. 83, Issue 5 (Dec. 1993) pp. 1090-1111.

[10]A "long position" is a financial stake that increases in value when the price level or quoted rate of an asset, index, or product rises. A "short position" is a financial stake that increases in value when the price level or quoted rate of an asset, index, or product falls. A "short sale" is a short position that arises from the sale of a product not owned by the seller. Here, the seller borrows and sells another's asset with an obligation to return the asset. To close the short sale, the seller buys back the same

price of the product in the less liquid market in order to increase (or decrease) the price in the related more liquid market, benefiting the trader's position. On a net basis, the trader would profit from the manipulation strategy if the absolute value of the gains in the more liquid market exceeds the losses in the less liquid market.

The necessity for relative differences in liquidity is illustrated in a case where a market exists for a single asset in which purchases and sales affect the trading price. In this market, the trader can push up prices with additional purchases; however, when he attempts to realize profits at the higher prices, his sales depress the price, eliminating his ability to generate a positive return through the manipulation. This emphasizes the importance of markets with different liquidity.

In the presence of two assets with different price sensitivities, price manipulation is possible under the following conditions: First, we suppose that the change in the value of the financial derivative product is sensitive to changes in the value of the physical spot product (e.g., changes in the price of the physical spot product affect the market value of the derivative instrument as a consequence of the correlation between the two). Second, the market for the physical spot product is less liquid than the market for the associated financial derivative instrument (i.e., there is a greater price impact for a given purchase of the physical spot product than there would for the associated derivative security). Under these assumptions the loss from manipulating the physical price (due to the direct price impact) would be less than the potential profit on the derivative because of the difference in depths between the two markets and the ability to implement a large-scale futures trade. As this discussion suggests, the physical spot and derivative instruments are correlated, and the spot market has less depth than the market for the derivative security, thus generating the ability to manipulate the physical spot market to profit in the financial derivatives markets.[11]

Interesting perspectives about these features are included in the depositions of Enron's natural gas traders. The trader that evidence indicates planned the manipulation stated in a deposition that:

> " ...there tends to be more of a correlation between people watching the Henry Hub than any other location because that is the physical delivery point of the [NYMEX] futures contract.

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asset and returns it to the owner. The short sale is profitable if the price of the asset falls, allowing the short seller to buy back the asset at a lower price.

[11] Futures Manipulation with "Cash Settlement," P. Kumar and D. Seppi, *The Journal of Finance*, Volume 47, Issue 4 (Sep. 1992), pp. 1485-1502 provides a formal analysis of the manipulation of a futures contract in this manner.

> So people watch that much more often than they watch any other point in the United States." [12]

Of course, the correlation reflects the settlement procedure for the futures contract.

Another trader, who worked on the same team as the above trader, provided further detail on the correlation of the Henry Hub next-day physical market and the NYMEX futures contract. When asked, "in your expertise as a gas trader, how large do you expect that correlation to be, based on your historical knowledge of correlations between the [NYMEX and the Henry Hub spot market]?", he stated:

> "I am not a statistician, but I would think that it's probably higher than 80 percent."[13]

Another element necessary to the manipulation is that the financial derivatives markets must have greater liquidity than the physical markets. The relative illiquidity in the physical market provides the trader with the opportunity to push the price up (or down) with his purchases (or sales). The liquidity of the financial market allows the trader to take a relatively larger position in that market without pushing prices up or down when entering or exiting that market. The financial markets are generally known to be far more liquid than the spot physical markets. Regarding the issue of relative liquidity, one Enron trader who worked on the team that manipulated the Henry Hub next-day market stated:

> "The volume of cash that is trading is insignificant compared to the amount of futures contracts that are trading."[14]

The questioner then asked, "So you would say that the NYMEX futures market is far deeper or more liquid than [the Henry Hub next-day market]?" The trader responded:

> "Extraordinarily."[15]

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[12]For the analyses provided in this chapter, Staff primarily used data extracted from Enron databases. Staff also used data provided directly by Enron to FERC in various electronic and printed formats. Other than data, Staff primarily discovered the reported information from interviews and depositions with natural gas traders and managers and from discovery provided by Enron. Because of ongoing investigations by other agencies, the confidential and proprietary nature of information provided in discovery, and the forward-looking nature of this investigation, Staff recommends that the Commission not provide sources for the information generated through interviews and depositions at this time.

[13]Id.

[14]Id.

[15]Id.

These elements provide the foundation for the manipulation of the natural gas physical markets in order to generate net positive returns by relatively larger investments in the financial markets.

The General Strategy of Manipulating the Financial Markets Through Trading in the Physical Markets

Overview of Manipulation Strategies

The relationship between derivatives transactions and the underlying physical products provides opportunities to profitably manipulate the natural gas markets. During the investigation, Staff recognized trading methods used to manipulate the physical markets to profit in the financial markets.

A number of variations are described in the following paragraphs. These variations do not exhaust the possibilities but are intended to provide a general framework to help the reader understand the actual manipulation that took place.

Strategy To Profit From Upward Movement In Natural Gas Prices

In the first and most straightforward example, a trader enters a relatively large long position in natural gas financial derivative contracts that will settle in the near future (within the month). This position reflects a "bet" that the expected price of natural gas will rise. Once the large position is in place, the trader aggressively purchases physical natural gas in the spot market, causing an actual increase in the spot price for natural gas and increasing the expected price of gas in the near future as well. The change in expected future prices causes a rise in the market value for financial derivative contracts settling on or near those future dates. To be profitable, it is essential that the trader place a larger position in the financial market compared with purchases in the physical market. As long as the trader obtained a large enough long position (a large enough "bet" on rising prices) prior to the physical purchase of gas, profits from the long position should exceed losses from buying the physical gas aggressively to push up prices.

Once prices are lifted, the trader must close out or neutralize the long position in financial derivative contracts by settling the contracts or by entering offsetting short financial transactions. Once the trader realizes

profits, the physical long position is reduced to match actual needs. The sale of gas necessary to reduce the position creates downward price pressure, just as the initial purchase of the gas created upward price pressure. This may cause the trader to sell the physical gas at a loss. However, the loss is expected to be more than offset by profits in financial derivative markets, where the desk manager held relatively larger positions.

Additional Profit Potentially Yielded From Cornering the Market

As discussed above, when selling the physical spot gas the trader will likely push down the price and potentially sell the gas at a loss. However, in some cases, the trader attempts to benefit from "cornering the market." The trader just purchased a large amount of the gas available in the next-day physical market. That trader may attempt to extract monopoly profits by demanding a premium from those who need the gas. The trader would attempt to do this by selling gas at a premium, late in the trading day, to purchasers who are unaware of the manipulation. This would presumably defer the expected drop in prices to a point after the purchasers are satisfied.

Earlier, as prices were rising, those purchasers sold gas into the market and expected to buy the gas back cheaper later in the day. However, late in the trading day, those who sold gas that they needed or those who delayed purchasing due to the high prices might be willing to purchase the gas at a premium if they fear that prices will not fall by the end of the trading day and if they have no reasonable alternatives to secure physical gas supplies (such as withdrawing gas from storage or drawing extra gas from the pipeline, which creates an imbalance and potentially generates imbalance penalties). These traders might be willing to purchase gas at premium prices because of the potential that the price of gas will not fall before the trading day ends, to avoid penalties, to run generators, or to fulfill unavoidable delivery obligations.

Strategy To Profit From Downward Movement in Natural Gas Prices

An opposite strategy can be executed with the goal of pushing down prices. The trader can enter a short position in natural gas financial derivatives that will settle in the near future. Following the placement of the short position, the trader sells natural gas in the spot market, which pushes down the spot price. The lower spot price is expected to reduce the expected gas prices for delivery in the near future. Assuming this happens, as the price goes down, the value of the short derivative position rises. To realize profits, the trader would close out or neutralize the short financial position by settling the financial contracts or by entering new, offsetting long financial transactions.

After closing the derivative position, the trader purchases back the physical gas to cover his short physical position. The purchase of the physical gas may generate a loss, however, if the trader executed a large enough financial derivative position to generate profits that exceed these losses; the strategy then remains profitable on a net basis. This strategy underscores the point that profitable market manipulations can involve what, in isolation, appear to be a beneficial drop in the price of physical gas.

An Alternative Variation in Which the Trader Gains Profits From the Downward Movement in Prices

The first manipulation strategy described above, in which the trader attempts to profit from rising prices, can also generate profits from the downward motion of prices following the trader's aggressive purchase of gas. When the trader pushes up the physical gas price by buying physical gas, he expects that prices will reverse after the manipulation ceases. In addition, if the trader did not obtain a short physical position prior to the manipulation, he will need to sell the physical position he acquired. This selling pressure will enhance the downward price movement following the manipulation.

In this variation, the trader does not need to enter a derivative position at the outset. Instead, the trader first purchases physical spot gas aggressively to push up the spot price. Then, while prices are high, the trader enters or increases short financial positions. Once the short position is in place, the trader sells the long physical position, thereby causing prices to decrease again and increasing the value of the short financial position.

The apparent benefit of this strategy is that the trader can increase the derivative positions after or while affecting the market prices of the physical product. This provides the trader with the opportunity to test market strength and gain information regarding the market's potential response. For example, the trader might learn that there is no interest in buying at certain levels, outside of the trader's own purchases, verifying the increased potential for downward pressure when the trader stops buying and especially when the trader sells.

The Central Desk Manipulation

Enron's central desk was primarily responsible for trading gas and making markets for locations in the central United States. However, that desk was not responsible for making markets at the Henry Hub; Enron gas traders were generally allowed to trade all locations in North America.

According to information gained through interviews, depositions, data analysis, and document review, the desk manager apparently performed a market test to move Henry Hub natural gas prices and, soon after, executed an actual market manipulation. The market test occurred on June 14, 2001 and the market manipulation occurred on July 19, 2001. On both occasions, the desk manager manipulated the price of the Henry Hub next-day physical gas product. The manipulations differed in approach and resulted in somewhat different outcomes.

The manipulation relates to the strategy described above. Staff believes the manipulation was intended to first increase the market price of natural gas at the Henry Hub, then enter short financial positions while the market was artificially high, and then push the market down. In an interview, an Enron trader admitted to a manipulation of the Henry Hub market to profit in the derivatives markets in the spring of 2001. Details of that manipulation and its design arose from additional interviews and depositions. An analysis of the Enron database isolated June 14, 2001 and July 19, 2001 as the dates of the potential manipulations. The July 19, 2001 manipulation was further supported by additional corroborating evidence, including a transfer of funds that, according to the depositional testimony of Enron traders, related to the manipulation. The patterns of the manipulations revealed in the data are further supported by the unusual role changes and actions of particular Enron traders. Staff first discusses these role changes and actions and then reports the manipulations in detail.

Unusual Circumstances Surrounding the Trading Activity

Because of the desk manager's regional trading desk management position and the manner in which he executed the trades, these transactions are highly suspect. During the market experiment and the manipulation, the desk manager traded a next-day physical product, an unusual act for a person in his position. In the normal course of

business, the trades would have been executed by someone in a subordinate position. Moreover, the next-day physical product of one region typically would not be transacted by traders making markets or scheduling gas for a different region.

The desk manager did not trade the physical product to satisfy actual physical needs. During the June 14, 2001 market experiment, within the trading day, he first sold and then bought 360,000 MMBtu. The resulting net purchase of physical gas amounted to zero, reflecting no actual need for gas by the end of the day.

A very liquid financial derivatives market existed for exactly the location in which the desk manager chose to trade physically. If he had intended to take a position in anticipation of a value change for the Henry Hub location, the far more liquid August OTC swap (NYMEX look-alike swap) would have been the likely vehicle because of its financial settlement, liquidity, and direct dependence on the Henry Hub location. Transactions of the size traded by the desk manager would not have affected the OTC swap price by as much, or at all, because of the greater depth or liquidity of that market.

On July 19, 2001, the date of the actual manipulation, the desk manager took a relatively large long position in the Henry Hub physical markets and then completely reversed the position a short time later, reflecting a need to sell gas by the end of the day. According to depositional testimony, on July 19 the desk manager took this position while unofficially acting as market maker for the Henry Hub. The market maker is the Enron trader assigned to always quote both a bid and an offer price, representing Enron's willingness to always buy or sell gas during market hours. The desk manager took over the chair of the Henry Hub next-day physical market maker and executed his transactions directly with EOL counterparties. Other Enron traders testified that the desk manager's action was unusual; in addition, the temporarily displaced market maker was officially supervised by a different desk manager.

The actions of the desk manager on July 19 generated losses in the book of the market maker whom he unofficially displaced. Depositional testimony revealed that a transfer of $86,000 to the market maker on the day of the manipulation covered the losses to the market maker generated by the desk manager.

Trading large amounts at once or, alternatively, trading many times over a short period, can create supply/demand imbalances and can cause executions at relatively bad prices. During both of the manipulations, the desk manager traded many times and in a short time

interval. He could have traded at a slower pace, allowing the market to absorb the additional supply or demand. However, on June 14 he purchased a large amount of gas in a very short period and on July 19 purchased and sold relatively larger amounts at an equally fast pace, generating losses on both days by this manner of trading.

The June 14, 2001 Market Test

During a search for what turned out to be the July 19, 2001 manipulation described in the next section, Staff discovered an earlier apparent market experiment or test that involved smaller physical volumes and relatively small financial derivative positions. In executing this test of the next-day physical Henry Hub price, the desk manager sold 360,000 MMBtu slowly on the EOL trading platform during the earlier half of the trading day, obtaining a net short position of 360,000 MMBtu. He then purchased the same amount in just 19 minutes, driving the price up significantly. The NYMEX price rose along with the next-day physical gas price.

For a short period following the desk manager's purchases, an Enron trader assigned to that desk manager entered short positions that would profit from a drop in the NYMEX swap price. Staff believes that the Enron trader may have placed his short position with the expectation that prices would return to premanipulation levels after the desk manager ceased generating the appearance of excess demand. Staff views the physical and financial trades as suspicious because of the involvement of these traders in the July 19, 2001 manipulation and concerns regarding the actions of the desk manager described above.

Staff views the June 14, 2001 manipulation as a market test or learning experience. Staff found only a small amount of financial derivative transactions acquired in a manner consistent with foreknowledge that a manipulation would occur. It is Staff's opinion that the manipulation may have been a test of the market or a learning experience for the manipulators. Staff believes that the market test was profitable, but generated minimal profits. The trader (trader 1), whose position changes were consistent with participation in the manipulation and who claimed to plan the strategy, earned approximately $55,025 in financial trading profits while the losses generated from the physical manipulation amounted to $36,500, resulting in net profits of $18,525. According to depositional testimony, trader 1 claimed to have devised the scheme but denied implementing the strategy. Trader 1 worked directly for the desk manager.

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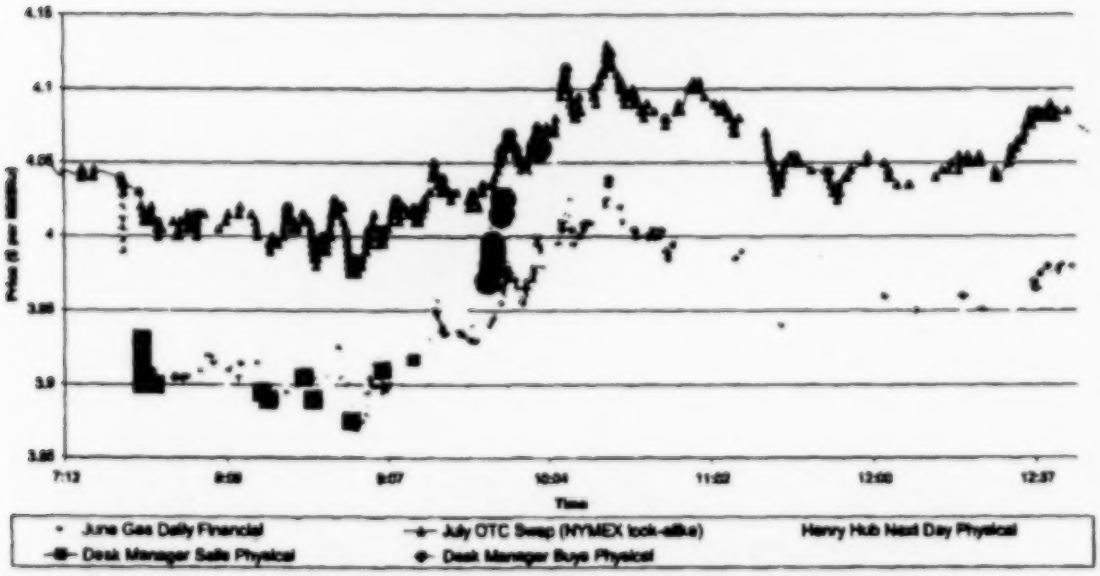
The details of the June 14 market test are as follows.[16] On June 14, 2001, between 7:39 and 9:04 a.m., the head of the Central desk (the desk manager), in 12 separate transactions, sold a total of 360,000 MMBtu of Henry Hub next-day physical gas to the EOL market maker for that product. During this period the price of the next-day natural gas fell slightly, from $3.93/MMBtu to $3.91/MMBtu. The desk manager accumulated a net short position of 360,000 MMBtu of Henry Hub next-day physical gas during this time.

Between 9:42 and 10:01 a.m., the desk manager completely reversed the position by purchasing a total of 360,000 MMBtu in eight transactions. As the desk manager aggressively bought back the gas he had sold, the market price rose significantly. His first purchase of 50,000 MMBtu at 9:42 cost $3.97/MMBtu and his last purchase in the 19-minute timeframe cost $4.06/MMBtu. The desk manager lost a total of $36,500 executing these trades.[17]

Figure IX-1[18]

The Relevant Hours: Comparison of Spot and Short-Term Henry Hub Based Physical and Financial Product Prices on June 14, 2001*



*Larger sized points reflect that Desk Manager's average purchase size equalled 45,000 MMBtu and Desk Manager's average sale size equalled 30,000 MMBtu, while non-Desk Manager trades averaged 13,808 MMBtu.

[16]For a detailed description of trader 1's financial trading positions and profits for the June 14, 2001 market testing manipulation, see Appendix IX-A.

[17]Average sale price less average purchase price multiplied by the total volume purchased (which equaled the total volume sold exactly) equals $36,500.

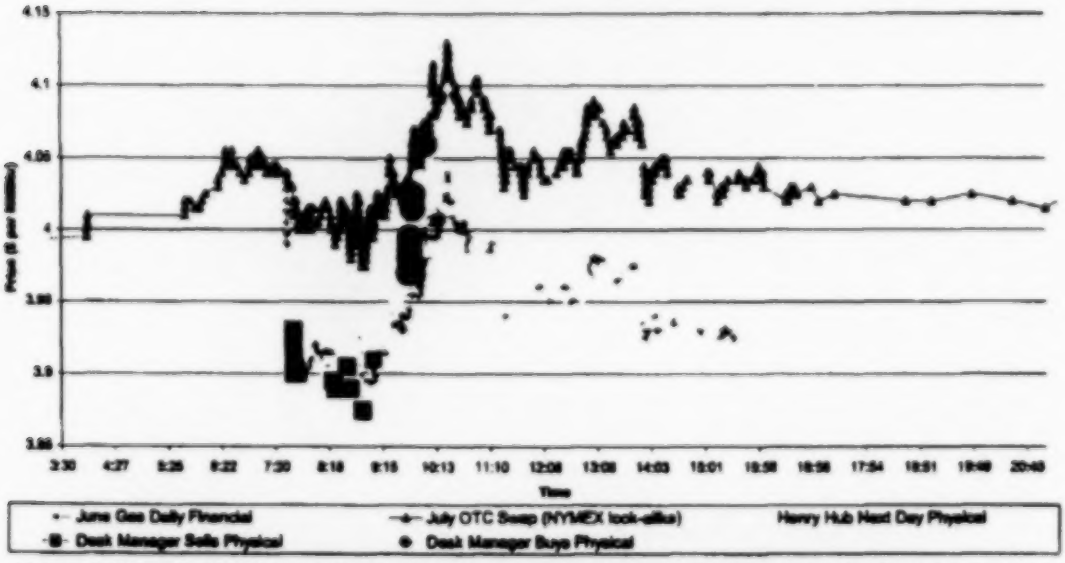
[18]With regard to all figures in this chapter, color prints are necessary to fully understand the details of the manipulations.

Although it took 1 hour and 25 minutes to obtain the short position, it took only 19 minutes to reverse the short position. After 10:01, the price of the next-day gas increased further, to a high of $4.10/MMBtu, before the last trade at 10:45 at the price of $4.06/MMBtu.

Trader 1 was positioned to profit from this market test. Trader 1 entered into a short financial derivative position that would profit from a downward movement in prices. He then substantially increased a short position in OTC swaps during the brief time period when the Henry Hub physical markets pulled up the related OTC swap transaction prices. Trader 1 then closed most of the position at a point where the market price for the OTC swap briefly jumped up, reducing the profitability of trader 1's positions. Trader 1 continued to hold the remainder of his position through the close of trading on EOL, when the OTC swap traded down to near the opening price for the day, thus increasing trader 1's profits.

Figure IX-2

Comparison of Spot and Short-Term Henry Hub Based Physical and Financial Product Prices on June 14, 2001*



*Larger sized points reflect that Desk Manager's average purchase size equaled 45,000 MMBtu and Desk Manager's average sale size equaled 30,000 MMBtu, while non-Desk Manager trades averaged 13,806 MMBtu.

The market test generated an insignificant amount of profit. However, in terms of moving the market price, the scheme proved successful. More importantly, this scheme preceded a greatly expanded scheme that occurred about 1 month later and generated significant profits.

The July 19, 2001 Manipulation

Overview

The July 19, 2001 market manipulation is most similar to the strategy described in this chapter in the section titled "An Alternative Variation in Which the Trader Gains Profits From the Downward Movement in Prices." The July 19 manipulation involved the desk manager, a number of traders, and the EOL Henry Hub next-day gas market maker.

A number of traders entered relatively large short positions in the financial markets through OTC swaps and *Gas Daily* financial swaps. These traders continued to increase the short positions throughout the initial phase of the manipulation, which was the period when the EOL market maker (who was, at times, the desk manager) quickly and steadily raised prices on EOL, resulting in the purchase of a very large amount of next-day physical gas. This purchasing caused prices in the financial markets to rise, but by a lesser amount.

The financial traders stopped increasing their short positions near the end of the EOL market maker's buying streak at a point when the EOL market maker stopped raising prices and began to hold prices steady at the high levels. Once the EOL market maker leveled out prices, the OTC swap began to fall. The EOL market maker then began to lower the prices and sold a very large amount of gas at rapidly falling prices. The falling of the physical price then further pushed down the OTC swap price, generating significant profits for the financial traders. These profits greatly exceeded the losses that were generated from the impatient buying and selling of the physical gas.

The physical volumes associated with the above physical manipulation were as follows. Prior to the manipulation, the market maker first accumulated a net short position of 124,613 MMBtu. Then the desk manager, acting as the market maker, drove up the price of gas by buying physical gas at higher and higher purchase prices, generating a net long position of 587,237 MMBtu. This reflects that Enron's net position changed by 711,850 MMBtu. The selling streak that followed resulted in a net short position of 315,191 MMBtu, or a net change of 902,428 MMBtu. The larger amount of sales on a net basis indicates that Enron intended to ultimately push the price down.

According to the financial data, at least eight traders from the Central and East desks (eight traders) positioned themselves to profit from the manipulation in a very timely manner. In the prior June 14, 2001

market testing manipulation, the desk manager traded gas with the EOL market maker. In the July 19, 2001 manipulation, the desk manager took direct control of the EOL Henry Hub next-day physical market by taking over the market maker function and posting bids and offers directly, on behalf of EOL, and in the name of the displaced market maker.[19] This direct control of the price setting function provided the desk manager with an ability to manipulate the market more precisely.

Just after 9:20 a.m., the desk manager began to raise the price of Henry Hub next-day physical gas. During this time, the eight traders significantly increased or obtained net short financial derivative positions. When the desk manager stopped raising the purchase price for a short period and then began lowering the price, the OTC swaps began to drop (reflecting downward movement in the NYMEX). The desk manager then began to aggressively sell off the gas he had just acquired, strengthening the downward movement. By the end of the day, Enron had obtained a significantly large net short position as EOL continued to sell more physical gas on a net basis after already having sold off the net long position. The OTC swaps and the *Gas Daily* balance-of-the-month contracts fell significantly past the opening price, generating profits for those traders who entered or maintained short positions.

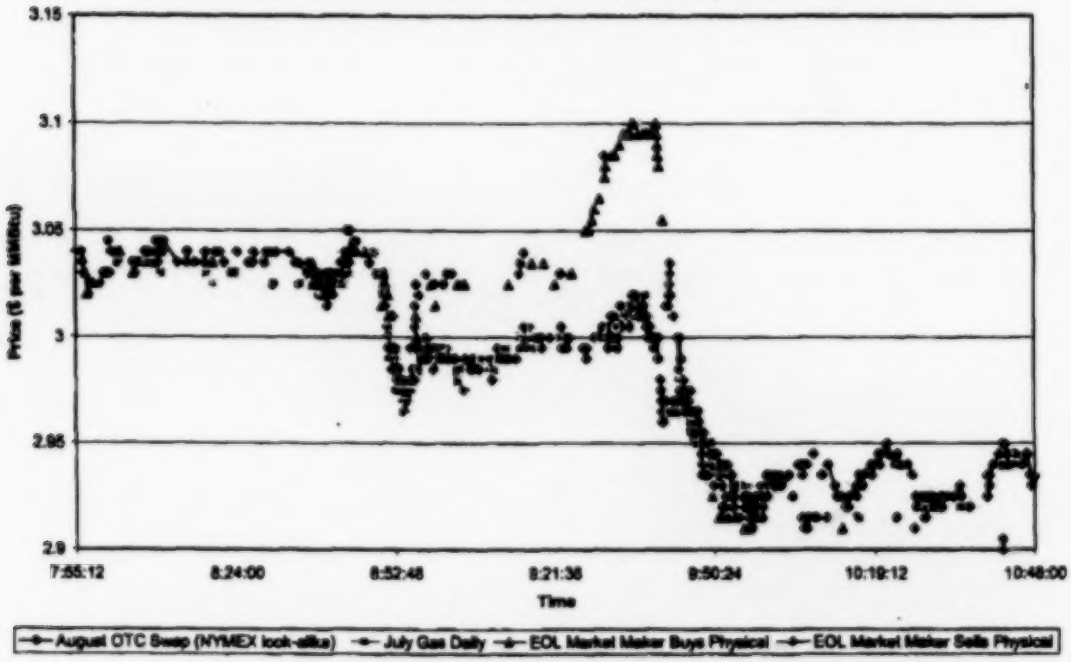
Details of the July 19, 2001 Market Manipulation

The day began with the physical book slowly growing short. In other words, by 9:22 a.m., Enron sold 124,613 MMBtu more of the next-day gas than it had bought. During this period, which lasted almost 2 hours, the price of gas rose a net $0.01/MMBtu from an opening first trade of $3.02 to $3.03/MMBtu at 9:22 a.m.

[19]According to depositional testimony and verified by electronic financial records, the desk manager agreed to cover the losses that he would generate in the name of the market maker. See footnote 11.

Figure IX-3

July 19, 2001 Morning Hours: EOL Henry Hub Next-Day Physical Market Maker Activity and EOL-Based Transaction Prices for Related Financial Products



At 9:22, the selling ended and the market maker began a buying streak. The market maker raised the price at which it was willing to buy the next-day gas. Many sellers came in to take advantage of the increasing prices. The EOL market maker offered such a generous price that, in just 19 minutes, the next-day gas platform purchased gas 43 times while selling gas only a single time. The price peak was reached at 9:35, just 13 minutes after the buying streak began. From 9:35 through 9:40, the next-day gas bounced along a ceiling of $3.10/MMBtu, creating an apparent top. The NYMEX crept upward from $3.00 to $3.02 from 9:22 through 9:36, but then began to decline a few minutes after the ceiling at $3.10/MMBtu had formed.

A very interesting phenomenon occurred at this point. The EOL market maker began reducing the price at which it purchased gas, but continued to only buy gas. By reviewing the trading behavior in Figure IX-3 in detail, Staff identified this strange pattern in which the EOL market maker drove the price up by offering a strong bid price and then creating a top, and then began a downward slide, all while selling gas only once.[20]

[20]See the section below for a more detailed description of the physical manipulation.

Following this unusual buying behavior, at 9:41 the market maker ended the buying streak and began strongly selling gas. Just prior to the selling streak, the market maker held a net long position in the next-day gas of 587,237 MMBtu.

During the market maker's buying streak, prices in the financial markets followed the physical markets upward but to a lesser extent. This emphasizes the unusual and puzzling nature of the market maker's behavior; he continued to buy the physical product even as it became extremely expensive and disconnected from the financial product. However, the EOL market maker now had a huge store of physical gas that it could sell to move the physical price down. During his deposition, trader 1 denied manipulating the market but claimed to have devised the manipulation strategy consistent with the facts of the July 19, 2001 manipulation. With regard to that strategy, trader 1 stated:

> "[W]e were trying to find out if this strategy would work and if Enron would make money if this strategy worked. So if prices went up and [the market maker] would make money by people buying the gas back at a higher price, if they didn't go up then she had to sell it. There is a chance you could sell OTC [NYMEX] swaps and benefit from the downward movement in the Henry Hub physical and that would offset the losses of selling the actual physical at a lower price."[21]

In the next 8 minutes, by 9:49, the market maker sold gas 31 times in a row without buying gas once. The price of the next-day gas at this point fell to $2.935/MMBtu. By 9:54, through these sales, the market maker had reversed the intraday long position to a short position. The price for the next-day gas at this time equaled $2.915/MMBtu. More important for the success of the manipulation, the NYMEX would need to follow and it did so. The OTC swap traded at $2.925/MMBtu at 9:54, which was down from the peak of $3.015 during the earlier part of the manipulation. Until 10:42, the last trade of the day, the market maker continued to be a net seller of gas. By the last trade of the day, the next-day gas traded for $2.905/MMBtu and the EOL next-day gas market maker closed for the day with a net short position of negative 315,191 MMBtu. At 10:42, the OTC swap traded at $2.945/MMBtu. The OTC swap continued to trade in a range from $2.915 to $2.96/MMBtu. At 2:30, the end of the NYMEX futures exchange trading day, the OTC swap traded at $2.935/MMBtu.

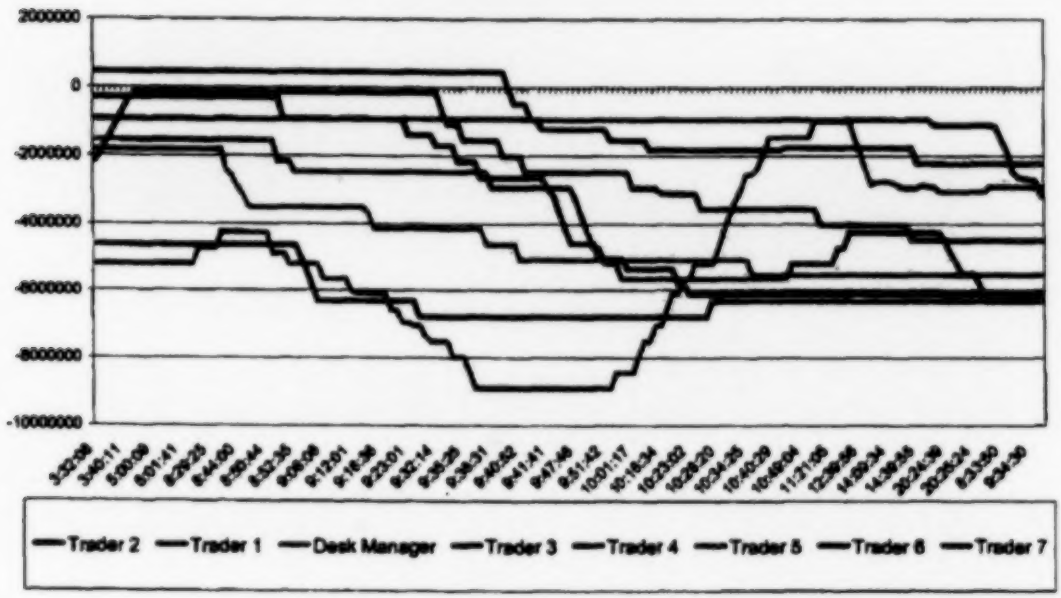
[21] See footnote 11.

Traders' Positions and Profits

Figure IX-4 shows the positions of a number of traders who knew or may have known about the manipulation of the Henry Hub next-day physical gas product. The manager of the Central desk and trader 1 are represented by the colors pink and yellow, respectively. Each of the traders represented in the figure worked on either the Central desk or the East desk (the desk of the official market maker for the Henry Hub next-day physical product). Each of the traders was positioned to profit if the NYMEX fell. These traders increased their short positions during the manipulation.

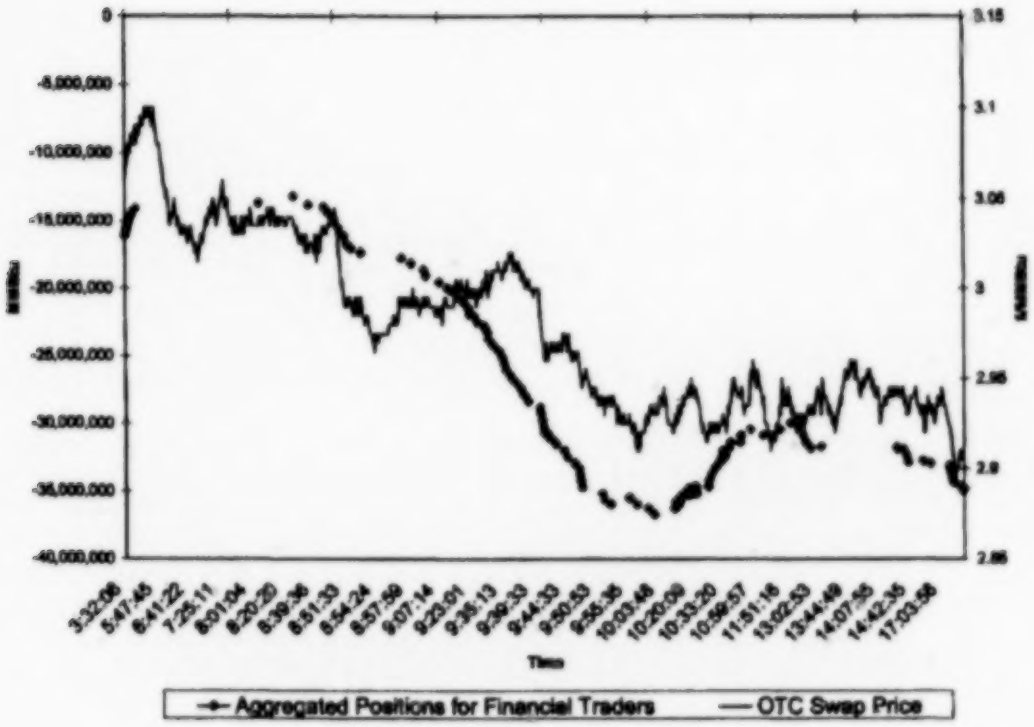
Figure IX-4

Net August OTC Swap Positions and July *Gas Daily* Financial Position Changes for Trades on July 19, 2001



As shown in the figure, the traders began the day with a net short position and the position grew shorter between approximately 8:40 and 10:00 a.m. We combined the trades of the eight traders in Figure IX-5 so that the financial position changes could be seen clearly in an aggregated manner.

Figure IX-5
OTC Swap Trading



Staff calculated that these eight traders generated a total profit of $3,181,756 during the day from their net short positions in the August NYMEX contract and the balance-of-the-month July *Gas Daily* financial swap.[22]

Regarding the losses that accrued on the physical side, the EOL market maker for the physical Henry Hub next-day gas product lost approximately $86,000 during the manipulation, but was made whole by a payment from the desk manager.[23]

[22]Deciding where profits continue to arise from a manipulation and where they cease to arise is a difficult and somewhat arbitrary task. The profit calculation values existing positions at the first transaction price posted for the day. The calculation values all positions that remain open at the end of the day at the price of the last transaction of that day. Other than considering existing positions at the start of the day, profits were calculated in the manner described in Appendix X-A for the June 14, 2001 manipulation.

[23]See footnote 19.

Understanding the Market Maker's Physical Transactions

The description of the July 19, 2001 trading day revealed a strange pattern in which the market maker began to strictly purchase gas and dictate the upward movement of the price, the price ceiling, and the initial downward movement. Then through sales, the market maker dictated the larger downward movement of the price. Finally, at the end of the trading day, the market maker maintained a low price through pricing with a bias toward sales by the market maker.

The market maker's function is to make a market in a product by putting out both an offer to buy gas (bid price) and an offer to sell gas (ask or offer price). The market maker generates profit from a spread between the bid price and the ask price. The ask price should always exceed the bid price because for the market maker to be profitable, he needs to sell gas at prices that exceed the price at which he is willing to buy gas.[24] The market maker generally seeks to post a spread that values the product fairly. As supply and demand change, the market maker modifies the spread. For example, if more buyers come to the market than sellers, the market maker raises the price of the product to reduce the demand to buy the product by making it more expensive. If the market maker fails to adjust the spread to raise the price, the market maker will sell too much gas and fall short. To buy back the gas, the market maker will have to raise the price at which he is willing to buy gas, unless market conditions change. This would generate a loss. In illiquid markets, market makers will tend to set wider spreads to generate larger returns in return for taking on greater risk that the market maker will not be able to find buyers and sellers at all times and therefore may need to hold product for longer periods than he would like. With this understanding of market making, consider the market maker's trading on July 19, 2001, as seen in Figure IX-3.

In Figure IX-3, the market maker's actions are intentional. This is not a case in which the market maker passively failed to adjust prices given changing market conditions. In this case, the market maker raised the price significantly, attracting more and more sellers to the market. The market maker is informed that he or she is the cause of the market price change, but the others are uninformed. They might assume that a large buyer (or buyers) is pushing up the price of gas.

[24] If the bid price exceeded the ask price, it would be profitable for traders to buy from the market maker and immediately sell back to the market maker. Therefore, whenever transactions do not occur, the ask price must strictly exceed the bid price.

The market maker is offering a price that is so far beyond the market's supply and demand conditions that traders only sell to the market maker for an extended period of time. Yet, interestingly, the price continues to rise. Next, the price begins to form a top where sales to the market maker continue for about 5 minutes, at or near $3.10/MMBtu. The market maker could have chosen to raise the price higher if he or she were willing to pay the price to the incoming sellers.

The market maker, after forming the top, chose to bring the price down. The data reflect that the market maker did not want prices to fall too quickly, so while prices were still above the fair market price, the market maker offered a bid that continued to solely attract sellers. Finally, as the price fell in a series of seven transactions from $3.10/MMBtu to $3.055/MMBtu, the market maker began to offer an ask price that solely attracted buyers. At this point the market maker sold the large amount of gas it had just purchased at steeply falling prices. The willing buyers began to come in at $3.015/MMBtu. The market maker sold off far more gas than he or she had acquired. The peak intraday volume of gas purchased by the market maker amounted to 587,237 MMBtu. By 9:54, the price had fallen to $2.915 and the market maker's intraday MMBtu position fell to just below zero. By the last trade, the market maker was short 315,191 MMBtu and the last physical trade was at $2.905/MMBtu, with a low of $2.89/MMBtu.

Description of EnronOnline and Its Main Features

In this section, Staff discusses the design of EOL and how it facilitated manipulation of the market, the economics of trading, alternative trading systems, and some forward-looking recommendations concerning energy trading mechanisms.[25]

[25]This section was prepared by FERC Staff with the assistance of outside consultant Chester Spatt, Mellon Bank Professor of Finance, Graduate School of Industrial Administration, Carnegie Mellon University. Comments and contributions were also provided by Professor Hendrik Bessembinder, Blaine Huntsman Presidential Chair in Finance, David Eccles School of Business, University of Utah.

The EOL Trading Platform

The EOL system was the first broadly successful Internet-based system for trading energy products. Enron established this trading platform so that it could serve as market maker in a broad range of physical and financial energy instruments. During the trading hours established for specific products, EOL offered (two-way) bid and ask quotes over the Internet. The quotes could be executed over the Internet directly by those entities with an EOL trading account. Outside traders continuously observed the posted two-sided quotes at specified volumes. These traders could instantaneously execute transactions at those quoted prices. As this suggests, the EOL platform was a one-to-many platform in which many counterparties (customers) were able to access the liquidity or apparent liquidity that Enron supplied.

The EOL system allowed the Enron market maker in a particular product to set up a schedule of prices (known as the "stack") from which customers could execute buy or sell orders. The customers can only see the top of the stack, which shows the current quoted bid and ask prices. Using a tool called the "stack manager," EOL is set up for Enron to be able to easily modify the stack that it offers on both sides of the market. For example, EOL may have offered gas at a particular location for $4.00 ask and $3.95 bid. In this case, an EOL customer could buy gas at $4.00 from EOL and sell gas to EOL at $3.95. As customers executed transactions on EOL for a particular product, the quoted ask and bid prices would be replaced with the next set of prices and quantities found in the stack. Different portions of the stack would be used, depending on whether an EOL customer bought from EOL ("lifted the offer") or sold to EOL ("hit the bid"). The Enron market maker specified the total volume of a particular product that he would be willing to buy or sell at the scheduled prices. The market maker could continuously alter the stack in response to both market information and the arrival of orders.

Alternatively, the market maker could set a function that increased prices by fixed increments as customers purchased gas and decreased prices by fixed increments as customers sold gas. For example, if EOL quoted an ask price of $4.00 for gas at a particular location and a bid price of $3.95, the EOL market maker could set a fixed increment at plus or minus $0.05. If this were the case, then if two customers bought gas consecutively, the ask price would rise to $4.05 after the first buyer lifted the offer of $4.00 (and the bid price would rise to $4.00). When the second buyer purchased gas, the ask price would rise

to $4.10 (and the bid price would rise to $4.05) following the purchase. If a customer then sold gas while the ask price was $4.10 and the bid was $4.05, that customer would receive $4.05 for the gas he sold and the ask price and bid price would fall to $4.05 and $4.00, respectively, following the sale. If the EOL market maker had created a schedule of price changes depending on whether customers bought from or sold to EOL, it is likely that prices would rise as customers bought and prices would fall as customers sold. However, as seen in the July 19 manipulation, the EOL market maker could choose what prices to post and mislead customers regarding the state of supply and demand.

The versatility of the EOL system also gave the EOL market maker the ability to automatically accommodate larger orders at less favorable prices. Large orders can potentially "walk up" or "walk down" the EOL stack established by the market maker. For example, a trader may pay a progressively higher price to purchase a large amount of a product through a series of transactions.[26] Additionally, the EOL market maker could instantaneously cancel liquidity offered by the EOL platform by modifying the quoted prices to unattractive levels (setting a very high asking price and a very low bid price).

The Lack of Transparency on the EOL Platform

Unlike the NASDAQ, from which timely electronic trade reports had been available to the public even prior to its transparency enhancing reforms in 1997, EOL did not offer timely reporting of executions. This means that EOL provided no data regarding recently executed transactions. Consequently, the market would not be viewed as "ex post transparent," i.e., even *after* the trades, basic market information was not provided to market participants. This made it difficult for traders to judge the current state of the market and forced traders to position their orders in a somewhat "blind" context.

As described above, EOL did not show the stack of prices and volumes. EOL only showed the best bid and the best offer for a specified relatively small volume of a product. This aspect of the EOL market design is similar to the former NASDAQ system, as that system lacks "ex ante" transparency. EOL did not display the potential liquidity available for orders of various sizes.

The absence of both ex ante and ex post transparency made it difficult for outside traders to understand both their potential trading opportunities and how well they did on past trades. Under the EOL

[26]The trading patterns of Reliant at the Topock Southern California Border point, described in Chapter II, reflect the "walking up" of the price of natural gas.

system, Enron had complete information on past executions on both sides of the market as well as the current liquidity being offered to Enron that it has elected to not execute immediately when it does not at least match the current EOL quote. Indeed, all of this detail is known by Enron at a completely disaggregated level by counterparty. This may have made traders reluctant to provide orders for execution. The lack of information makes formulating one's trading strategy particularly difficult. However, despite these imperfections, EOL improved market transparency (relative to voice brokers) by making continuous two-sided quotes available to all for the first time.

In the EOL system the EOL market maker was asymmetrically (extremely well) informed. In this system Enron had complete information on past executions on both sides of the market (including the participants associated with each transaction) and control over future quotes. This made many traders reluctant to trade on the platform. EOL was similar to the problematic pre-1997 NASDAQ system in which all customer trades in the NASDAQ equity market were executed with dealers and the quotes displayed were the best market-maker quotes.[27] Public limit orders, i.e., price-contingent orders from the public,[28] that would improve the quote were not displayed in the basic EOL design and such potential liquidity could not be accessed, except by trading with Enron.

Limit Orders on EOL

During the later portion of its operation, EOL accepted limit orders placed by its customers for inclusion in the EOL stack. These limit orders reflected customer willingness to provide liquidity, through offers by customers to buy or sell a product from or to Enron, at specific maximum or minimum prices and volumes not currently available on the EOL platform. These limit orders provided Enron with information on liquidity at the specified price levels by specified counterparties. When such limit orders were executed, Enron acted as the counterparty rather than matching the trade directly with another EOL customer. Effectively, all trades were still cleared using Enron as

[27] The inadequacy of that system and the collusion among dealers that was documented economically in "Why Do NASDAQ Market Makers Avoid Odd-Eighth Quotes?" W. Christie and P. Schultz, *Journal of Finance*, Volume 49, Issue 5 (Dec. 1994), pp. 1813-1840 and "Why Did NASDAQ Market Makers Stop Avoiding Odd-Eighth Quotes?" W. Christie, J. Harris, and P. Schultz, *Journal of Finance*, Volume 49, Issue 5 (Dec. 1994), pp. 1841-1860 led to the 1997 adoption of "order-handling rules" that facilitated the display and execution of public limit orders within a modification of the prior design as well as a $1 billion class-action lawsuit settlement. Unlike the NASDAQ system, EOL had a single market maker (Enron) as the counterparty on all trades, which is why we call it a one-to-many platform.

[28] A limit order to buy would specify a maximum purchase price, while a limit order to sell would specify a minimum selling price.

the counterparty so that the platform still essentially functioned as a one-to-many platform.[29]

EOL began to accept limit orders from its customers to enhance the attractiveness of its trading platform and increase the flow of information available to it by providing a vehicle for potential orders by outside traders who did not want to execute at the current prevailing price. Enron did not bypass the limit orders provided to it (e.g., it did not sell from its own account at a higher price when a limit order to sell from an outside trader existed in the EOL stack at a lower price) and would execute these orders prior to executing orders from its own book at inferior prices, i.e., the platform executed positions at more favorable prices first and followed "price priority."

The limit orders offered by outside traders provided to Enron an option to meet demands for immediate execution by others using these limit orders as a source of liquidity. The EOL market maker could also step ahead of the limit orders and trade from his own account, with the comfort that the additional demand to trade reflected in the limit orders would potentially move the price in a favorable direction. This would allow the EOL market maker to profit by positioning in the market prior to the impact on prices that the limit orders would generate when executed. These EOL customers, who provided limit orders to EOL, were not able to trade directly with one another using the platform. When matching buy and sell limit orders were provided to EOL, EOL would act as the counterparty to both.

The nature of the platform's structure, particularly the absence of transparency (both with respect to trade reporting and the lack of knowledge by outside investors of the limit order book), the effective inability of public orders to trade directly with one another, and Enron's inherent last-mover advantage (except for orders at the automatically executed quote), all contributed to Enron's overall advantage vis-à-vis the limit orders supplied to it.

[29]The caveat with this interpretation is that investors placing orders on EOL derived a benefit from public limit orders during the period they were allowed, as if the public investors are trading directly with one another.

The Role of EOL in Enron's Strategy and Market Power

At a fundamental level, EOL was an important part of Enron's business strategy. Prior to EOL, voice broker trading dominated the market. The use of the EOL platform provided a way to benefit from its willingness to make a market and supply liquidity. EOL offered a way for Enron to "market" its products, including positions that it had acquired through these trading activities. In addition, by operating a trading platform, Enron obtained considerable market information on resource flows and trader valuations from other market participants. Given Enron's substantial overall market position, its decision to concentrate its own trading (about 25 percent of the market) through EOL (thereby dramatically reducing its involvement in the voice broker markets) changed the industrial organization of those trading markets. Its decision to substantially reduce its participation in the voice broker markets reduced the information and liquidity available there.

A variety of advantages accrued to Enron from its operation of the EOL platform, many of which exploited its position as the dominant electronic platform. The platform met the need in the marketplace for an electronic platform that provided quick and easy trade executions. Through the broad acceptance of the EOL platform, EOL gained a successful first-mover advantage in which EOL was well positioned to exercise market power in the quoting process and earn rents in the form of wide spreads, or by exploiting its informational advantage.

This market power could also create benefits for Enron in its ability to extract information from trading firms, both about the level of demand for different instruments and the location and distribution of various energy products (which may be useful in working to meet future unanticipated needs).[30] Enron was also in a better position to capture profits in the financial derivatives markets using this information. More generally, Enron's information advantage would be valuable in helping it assess the information content of trades and orders.

Another example of the value of Enron's information advantage is the potential assistance it provided in deciding when conditions were ripe for a market corner or manipulation or helping it implement the manipulation or corner quickly. A final example of the value of

[30] Analogously, one of the advantages often attributed to Michael Milken's high-yield ("junk") bond group at Drexel Burnham in the 1980s was its knowledge of the ownership of most high-yield bonds.

information to Enron is in helping it identify "stale" orders with which it could execute opportunistically. The monopoly position even increased EOL's ability to undertake market experiments to further enhance its ability to extract information from its quoting behavior.[31] Indeed, these sorts of informational advantages are particularly strong when a platform possesses a large market share.

Even after the introduction of competing platforms (such as DynegyDirect and the IntercontinentalExchange (ICE)), much of EOL's earlier monopoly advantage continued because outside traders had become familiar and comfortable with the EOL platform. The effective cost to traders of learning a new platform gave EOL a considerable first-mover advantage that continued after competing platforms arose. These switching costs and the importance of a successful platform possessing considerable liquidity act as barriers to the entry of competing platforms. Consequently, the initial advantages of being the first successful platform to introduce electronic trading continued for EOL even after it faced competing platforms (even if they had potentially superior market designs).

The Role of EOL in Facilitating Market Manipulation

In earlier chapters of this Report, we described a market test and a market manipulation at the Central desk and also discussed the impact of Reliant's purchases of next-day natural gas at Topock during the winter of 2000–2001 on the markets. These examples illustrate how the design of the EOL electronic platform facilitated and contributed to these behaviors. As market maker, Enron observed the depth available in the order book across the relevant markets, unlike other traders, because of the absence of ex ante transparency. This allowed Enron to determine when conditions were ripe for a prospective manipulation, without this knowledge being available to other market participants. Furthermore, the lack of transparency reduced the likelihood that other participants would understand contemporaneously that the market was being manipulated. The lack of transparency limited the competition that Enron faced and enhanced its ability to exploit transitory changes in the depth across markets. The trading system provided Enron a continuous option to access liquidity through the orders provided by its clients. This gave Enron the option to move prices quickly if it chose

[31] An illustration of how experimentation in the quoting process in some markets can be used to create valuable information flow is shown in "Price Experimentation and Security Market Microstructure," C. Leach and A. Madhavan, *Review of Financial Studies*, Volume 6, Issue 2 (1993), pp. 375-404.

to do so, as it did in some of the instances of manipulation described in this Report. This seemed crucial to the implementation of this manipulation.

Enron gained considerable informational advantages from EOL. It alone observed the identities of the counterparties to all trades and, therefore, could observe the volumes and net purchases of every product by counterparty. For example, during the winter of 2000–2001, Enron observed the huge trading volume and net purchases of next-day natural gas at Topock by Reliant. This provided Enron a strong advantage in understanding the market dynamics. Enron would uniquely understand the extent to which the Reliant orders would be more informative and therefore would offer these orders relatively less depth, which means Enron would raise the price by a greater amount after Reliant purchased gas. Enron would do this in anticipation of additional purchases by Reliant, arising out of Enron's knowledge of Reliant's historical gas usage at the Topock point. This informational advantage was a consequence of the one-to-many structure, but would not be available to other potential liquidity suppliers to Reliant.

Outside traders of a particular product potentially possess more information than market makers. For example, a trader who needs to buy large amounts of gas is fully informed about his own remaining needs and possibly has other information that motivates his purchase of a large amount of the product. The market maker generally does not have this information. This suggests that rational market makers set their bid and ask quotations to reflect the information known about the corresponding bid and ask orders. When a rational market maker offers a two-sided quote, this dealer takes into account the information known about his customer's order in setting the quote and quoting higher prices to buyers than sellers. The market maker generally quotes less favorable prices for larger (more informed) orders.

Market makers are often viewed as having a distinct advantage with respect to their knowledge of the short-term price dynamics because of their direct observation of supply and demand (trading conditions).[32] This is especially true when liquidity supply is concentrated so that the information is not too dispersed. In the EOL system, where ex post or

[32]An interesting empirical study of this advantage is the study of the Chicago futures pits by "Life in the Pits: Competitive Market Making and Inventory Control," S. Manaster and S. Mann, *Review of Financial Studies*, Volume 9, Issue 3 (1996), pp. 953-975. In that study the advantage to the market maker from observing the flow of information arises in a situation with competing market makers. Of course, the advantages from observing the short-term liquidity dynamics will be much greater when that information is concentrated in a single dominant market maker, even if that market maker does not attempt to exploit its potential monopoly power, as with the EOL platform.

ex ante trade information is not provided to customers, the advantages to EOL market makers increase because none of the advantageous information is shared with others. Of course, it is precisely when liquidity provision is concentrated that there is also the greatest scope for monopoly power. This can manifest itself as the market maker setting relatively wide spreads between bid and ask prices and the extent to which the market maker extracts information from the flow of orders.

ICE and TradeSpark: An Alternative Type of Electronic Platform[33]

The Basic Structure of the Electronic Markets

The introduction of the EOL platform in late 1999 generated tremendous interest and attention, bringing electronic trading to the commodity markets.[34] It emerged as a very popular platform and appears to have facilitated Enron's ability to increase its market share. The EOL system itself was quite easy to use and provided quick executions (immediate trading). EOL brought a "screen" to the OTC energy market at a time when trading occurred through telephone "voice brokers." The voice brokers performed a matching function and would often need to search for liquidity by "working the market." In contrast, Enron's willingness to offer continuous liquidity to the marketplace (e.g., by maintaining two-sided quotes) was very attractive to market participants. From the perspective of many participants, the system provided a form of "price discovery" through the continuous availability of two-sided quotes, even though the quotes certainly reflected Enron's business interests. The ease of using EOL presumably helped contribute to the growth of the market by simplifying the ability to trade. Indeed, when EOL "went dark," the trading activity at ICE doubled as traders sought alternative electronic platforms.[35] [36]

[33] Information about IntercontinentalExchange (ICE) and TradeSpark was primarily provided by interviews with their respective personnel.

[34] Many equity markets around the globe (such as Toronto and Paris) moved to electronic platforms during the late 1980s and the 1990s (e.g., as illustrated by the analysis of the provision of liquidity in the electronic limit order market in Paris by "An Empirical Analysis of the Limit Order Book and the Order Flow in the Paris Bourse," B. Biais, P. Hillion, and C. Spatt, *Journal of Finance*, Volume 50, Issue 5 (Dec. 1995), pp. 1655-1689). In fact, the Toronto market licensed its electronic market structure to a number of other markets.

[35] When EOL closed, it is likely that many types of trading entities (including voice brokers and even alternative one-to-many platforms, such as Dynegy) increased their market share and overall business activity.

Although the introduction of an electronic platform facilitated risk sharing in the energy markets, many of the specific features of EOL were certainly not essential for a successful electronic platform. ICE and TradeSpark offer interesting examples of electronic commodity trading facilities designed from a different underlying premise. They have emerged as major trading platforms, particularly in the aftermath of Enron's collapse and the demise of its EOL platform. ICE and TradeSpark provide automated execution facilities (electronic markets) in which all traders have identical access and trading opportunities,[37] i.e., they serve as electronic brokers. The market systems at ICE and TradeSpark are fully transparent limit order market systems. The *entire* order book is displayed to all market participants and subscribers rather than just a two-way quote (e.g., the spread). By displaying the entire order book continuously, including the depths at various prices, the market exhibits ex ante transparency. Traders then know the full amount of committed or displayed liquidity that is available in the marketplace from various counterparties without further market reaction.

However, the identities of the clients submitting orders are not displayed, so that in this sense the market design is "anonymous." The ICE and TradeSpark platforms execute orders sequentially in a system in which *price and time priority* are respected. Price priority ensures that orders at better prices are executed prior to orders at inferior prices, while time priority ensures that orders at a given price are executed in order of submission. Immediately after order execution, trade prices and volumes are reported on ICE and TradeSpark.

The systems are ex post transparent because they provide timely transaction reports. Traders then know that other market participants entered into a transaction at the stated price, which gives them information about other market participants' assessment of supply and demand in this market. However, the privacy of trader identities

[36]Although ICE's market design is rather different from that of EOL, ICE does emulate EOL with respect to the broad idea of an easy-to-use electronic platform and such "bells and whistles" as operating out of the browser rather than just in PC mode. The transition in which ICE's activity increased at the expense of EOL occurred over several months.

[37]These differ in fundamental ways from EOL. The nature of the access to order flow information on ICE and TradeSpark also contrasts with some of the well-known U.S. trading floors (e.g., the New York Stock Exchange (NYSE), the Chicago Board of Trade (CBOT), the Chicago Board Options Exchange (CBOE), and the New York Mercantile Exchange (NYMEX)), in which specialists and floor traders have access to the flow of information and the right to trade on the floor is restricted to a limited number of members. The capitalized value of that access is illustrated by the market price of a seat (membership) on various floors. Differential access of market makers also arises in other market settings, such as the NASDAQ.

continues to be protected subsequent to the trade execution, except that the identity is disclosed after trading to one's counterparty to facilitate trading. This prevents other traders (except the counterparty) from exploiting information about one trader's interest in trading.

Credit Risk and the Organization of ICE and TradeSpark

A complication that arises in the ICE and TradeSpark platforms is the need to handle credit risks because the trading parties do not know the identity of their counterparty at the time of trade. This complication was not present in EOL because all parties trading with Enron knew their credit limits and standing with Enron. The basic contracting structure underlying ICE and TradeSpark is not a "clearing mechanism" in which the parties trade with a clearing corporation and "margin" (collateral value) adjustments are used to ensure the fulfillment of the contractual obligations (as in conventional futures contracts). Instead, these markets use a set of bilateral contractual arrangements to limit credit exposure to the contractual performance problems of its clients and maintain the overall credit matrix under which the parties define acceptable counterparties.[38] Each pair of counterparties trading with each other in the ICE platform is required to have a master contractual agreement. The actual transactions between the parties are bilateral, as the platform's role is to simply facilitate the matching of buyers and sellers and "confirm" the trade execution with them.

The ICE and TradeSpark platforms allow each firm to designate the firms with which it is willing to trade particular products.[39] The order book systems prevent ineligible counterparties from trading with one another. The order systems display any orders in the order book that the trader cannot access due to credit issues, and the system design prevents the execution of ineligible orders. Under these systems various clients face different subsets of ineligible (and eligible) orders. This design is a clever way to address the fundamental credit problems (whose centrality in commodity pricing has become especially apparent in the last year) and the diverse views of market participants about the creditworthiness of other market participants. Strikingly, this design can address the creditworthiness of the particular counterparty to a trade (through the prespecified credit matrix) without requiring

[38]The clients needed to make broad credit determinations outside the trading system. The platforms do not provide any information or services with respect to assessing credit worthiness, as they simply set up a mechanism for the customers to make their own determinations. The participants can then manage the controls provided to them.
[39]The systems allow flexibility in defining permissible counterparties. Depending on the system, these might vary with the type of product and also are subject to potential restrictions on the size of particular exposures (e.g., the customer can impose daily limits).

disclosure of trader identifications. However, the systems do not allow contract pricing to vary by counterparty beyond barring unacceptable matches.

To understand the implementation of this credit system it is important to recognize that, as in other electronic limit order markets, there is a *common* ranking of orders in the limit order book as orders are ranked by price and then by time of submission. Under price and time priority, an investor purchasing in the limit order market purchases the commodity from those offering to sell at the lowest price (price priority), purchasing the good in sequence by the time of order submission (time priority). The role of time priority in such markets is to increase the incentive for providing limit orders that enhance liquidity provision.[40] Orders are executed following price (and then time) priority, subject to the credit constraints (two parties can trade with each other only if each is an acceptable credit to the other in the specific product context). However, unlike conventional electronic limit order markets, at a global level departures from price and time priority can arise because the system will not execute a trade with a prohibited counterparty (e.g., in the ICE and TradeSpark displays an order seeking immediate execution skips over the inaccessible orders in the limit order book). "Inverted markets" (in which the bid price exceeds the ask price) can arise because of differences in who is eligible to post or trade quotes. If the same counterparty is eligible to trade with both the bid and ask quoters, then, ignoring credit risk, that party can earn "arbitrage" profits. For example, suppose one party is willing to buy at $4.00 and another is willing to sell at $3.95, but the two cannot trade with each other because of credit restrictions. In this case, a third trader who is allowed to trade with both parties can buy at $3.95 from the credit-inhibited seller and sell the same amount at the same time to the credit-inhibited buyer who posted a $4.00 asking price. Note that parties who are not able to trade at the best quote (because of credit issues) are still not squeezed out of the market completely.

Because of differences in their credit evaluations, different firms will trade with different counterparties. Firms with tight credit standards or, alternatively, firms with poor credit, will face higher execution costs. The markets that these firms face have less depth because of access to a more limited set of counterparties. The ICE and TradeSpark systems are intended to create a "Chinese wall" between the trader and the

[40]However, the role of time priority is modest if the pricing grid is tight (the trader can jump ahead of the queue for a tiny price concession). This is illustrated by the effect of decimalization on time priority on the New York Stock Exchange and NASDAQ. The minimum tick sizes on ICE and TradeSpark are very small (between $.01 and $.001 for various products).

client's credit manager. The same individual should not make decisions concerning both trading and counterparty credit risk. This is intended to avoid the conflict of interest in which the trader would maximize his trading profit by trading with as many counterparties as possible, assuming the trader does not bear consequences for any defaults.

The need for a Chinese wall emphasizes the vulnerability of the credit restriction system to collusion between the trader and the credit manager, as well as across firms. In particular, different firms that wish to undertake "wash sale" trades with one another can do so by identifying the remaining trading firms that can intervene and execute on the quote as unacceptable credit risks, thereby disabling the other firms from participating in the wash transactions.[41] The wash sales provide a mechanism to increase one's trading volume and potentially to manipulate the reported price.[42] As a by-product of the remainder of the trader's holdings, there may be natural incentives to provide false prices to alter the perceived value of the asset. Of course, in a conventional electronic market the ability to artificially move the price is limited because of the constraints of competing orders. For example, if a trader posts a price that is above fair market value, that trader faces the risk that another trader who is not involved in the wash trade scheme will execute on that posting.

The ICE platform provides notice to parties when their credit status changes. The ability to change the credit setting on ICE and identify rivals as not credit worthy greatly facilitates the ability to manipulate reported prices by wash sales.

Evidence indicates that certain members of the consortium that initially formed ICE did execute wash transactions by altering credit acceptance ratings so that they could only trade with a planned partner. The consortium incorporated a variable equity interest that provided incentive for the consortium members to trade on ICE. Ownership interests could rise with increasing transactional volumes by those owners. It appears that some consortium members attempted to increase that ownership interest through wash trades. They placed credit restrictions to prevent others from trading and then executed large trades.

These wash trades emphasize the importance of the ownership structure of the trading platform in general and specifically raise

[41]This occurred on ICE but could not occur on TradeSpark due to TradeSpark's requirement of allowing transactions only when there are a minimum number of potential counterparties.

[42]See Chapter VII, p. VII-14 for more detailed discussion on wash transactions.

questions about the suitability of the incentives provided to increase volume and whether the credit restriction mechanism can facilitate collusion among firms to create wash sales.

Contrasting ICE and TradeSpark With EOL

The contrast between the structure of EOL and these platforms is striking. EOL was initially organized as a dealer market (one-to-many trading platform), while ICE and TradeSpark were multilateral trading platforms (many-to-many trading platforms). Initially, it was intended that EOL would earn the dealer spread and support the trading activities of the parent firm, Enron, which was a major player in most of the underlying energy markets. Enron was the counterparty for all the trades on EOL. EOL lacked transparency as the order book was not displayed (except for its two-way quote) and trades were not reported. As a result of this lack of trade reporting, when prices quoted on EOL changed, investors would not be able to tell if those changes resulted from transactions or for any other reason. For example, the EOL market maker might have changed the price because market fundamentals changed or possibly to mislead the market.

In contrast, ICE and TradeSpark are pure brokerage systems based on a multilateral trading platform (these systems do not participate in individual trades), earning brokerage, confirmation, and data fees. They provide equal access and information to all eligible participants. The order book is always displayed and trade executions are reported in a timely manner.

Despite its informational structure and other features of the EOL platform by which Enron enjoyed major advantages, the EOL system itself was apparently quite popular. Nevertheless, many participants (who were also competitors with Enron) became frustrated with the EOL platform. For example, the formation of ICE and TradeSpark each reflected a consortium model whose partners (financial institutions and trading firms) were concerned about the monopoly power that had accrued to Enron in establishing EOL as the "marketplace." In the case of ICE, to help the market get started, the founders agreed to make initial order flow commitments (for relatively small amounts). However, due to the concerns Staff described earlier, and for other reasons, ICE is now evolving to an independent board structure and is trying to provide financial liquidity to its owners.[43]

[43]To mitigate conflicts of interest, information about rivals is not shared with the board and decisions as to which contracts to trade are viewed as business development rather than board issues.

Although EOL did not engage in trade reporting or order display to retain maximum advantage relative to its counterparties in the trading process, ICE is finding it valuable to publish more of the data because an important portion of its business model is to sell data. Since ICE itself is not a dealer, its sources of revenue are very different than those of EOL. Of course, broad sales of transactional data are a significant part of the revenue of major equity markets (such as the New York Stock Exchange and NASDAQ).

The Role of Voice Brokers

The major competition faced by electronic trading platforms is from voice brokers,[44] who perform a central role in searching for and matching potential counterparties to a trade. They are dominant across products (even for month-ahead products), except for the next-day instruments.[45] Voice brokers have recently become more important as credit issues are now extremely significant in the marketplace; when one trades through a voice broker, one's decision can be contingent upon the specific identity of the counterparty (even in the ICE and TradeSpark platforms one can only condition upon the counterparty being an "acceptable" credit). Customers also feel that they obtain valuable information for trading with the use of a voice broker.[46]

Many of the competing brokers are actually hybrids (a voice broker plus an electronic platform that serves as a "matching engine"). Voice brokers recently formed the Energy Brokers Association to develop a code of ethics for brokers.[47] It is important to note that Bloomberg, like ICE, does not have a voice broker; however, it has introduced an electronic platform called "Powermatch."

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[44]Voice brokers were the dominant portion of the trading system prior to EOL and continue to be widely used at present.

[45]Because of the industry commission structure, which is proportional to the underlying physical quantities, the single-day contract is not attractive to voice brokers. There are natural economic efficiencies in processing small trades in a relatively automated manner. This is somewhat parallel to traders preferring more customized handling of larger trades (to facilitate strategic handling of the order to minimize its potential price impact), but not smaller trades, for a given instrument. The mechanics of electronic market design are efficient in addressing a high volume of transactions. In short-term instruments there is a lot of trading and a concentration of activity within a few hours.

[46]However, at some level the information provided by voice brokers must form a "zero-sum" game (i.e., any information received is at the expense of someone else trading through that broker), although voice brokerage still can be an efficient trading system.

[47]The founding members are Amerex Group, APB Financial LLC, GFI Group Inc., Natsource LLC, Prebon Energy Inc., Starsupply Petroleum LLC, and TFS Energy LLC.

While there is considerable bilateral (OTC) trade in the sense that trades in many instruments do not go through a "clearing" exchange (such as the NYMEX), there is very little "direct" trade that does not go through an intermediary in the marketplace. Firms value the anonymity of using a broker and want the maximum amount of competition on the other side of their trade.[48]

Conclusion: Forward Looking Recommendations

As mentioned earlier in this chapter, Staff provided evidence of the manipulation of the physical natural gas market at the Henry Hub in Louisiana in order to profit in the financial markets. The structure of the EOL platform enhanced Enron's ability to perpetrate the manipulation. Informational advantages arising out of the EOL platform allowed Enron to directly apply the manipulation as market maker. EOL provided Enron the ability to better time the manipulation through the use of real-time data about individual market participants and by monitoring their responses. The ability to mislead market participants through complete control of the quote-setting process further enhanced Enron's ability to manipulate the market. Finally, the lack of transparency of the EOL system (in failing to provide information regarding limit orders and the stack, and in failing to provide information on past trades) enhanced Enron's ability to keep competitors in the dark.

As traders lose money in markets where they suffer significant informational disadvantages and manipulations, they may withdraw or reduce trading in those markets, thereby reducing liquidity. As liquidity falls, market makers will tend to demand higher fees because of the additional risks they bear as the difficulties in offsetting purchases and sales rise. These additional costs are borne by all companies that buy, sell, or hedge energy products.

Market manipulation also causes the misallocation of resources due to incorrect price signals. The inability to correctly value a particular energy product can lead to inefficient investment choices in energy plants and technology. The potential for future manipulation causes energy product traders to substitute away from instruments likely to be manipulated. As a result, there may be inadequate use of spot markets and excess precautionary use of storage and long-term contracts. Manipulation does not simply transfer wealth among market

[48]The one exception would be for a very few specialized products in which there are only a few potential suppliers.

participants; it causes deadweight losses to society as a whole by distorting consumption and investment decisions. The overall combination of costs and distortions applies not only to manipulation through market trades, but also to the false reporting of index prices to influence settlement prices for derivative instruments and direct bilateral contracts. These latter concerns are described in Chapter III.

Low-burden methods of gathering useful information exist and can be implemented at a very low cost. Additional information would allow Staff to more efficiently identify these manipulations. Voluntary disclosures by a gas trader in an informal interview led to Staff's discovery of the July 19, 2001 Henry Hub manipulation. Without these disclosures, it is unlikely that FERC Staff would have discovered the manipulation. Looking forward, Staff will need to be equipped with additional information to identify similar manipulations.

Staff needs the ability to quickly identify evidence of churning. In the investigation of Reliant's trading in southern California and Enron's trading at the Henry Hub, Staff identified evidence of churning (in which investors turn over their positions quickly rather than establishing stable positions based on long-term needs). Information about the identity of market participants and associated transactions is available to many of the markets (such as ICE and TradeSpark). This information would be useful to FERC on a historical basis and through a real-time data feed. It would enhance FERC's understanding of the markets' operation on an ongoing basis and could significantly enhance its monitoring and enforcement capacity and role. The selection of particular data filters and tests to monitor data would facilitate the automation of this review process.

A particularly important approach would be to monitor the markets directly for churning. For example, a "churn alarm," which would monitor for a large amount of net buying (or selling) in a short period of time, would be helpful in identifying aggressive trading behavior. While this would likely generate a high proportion of false positives due to the nature of liquidity provision, it could also identify more suspect trading behavior.

As Staff discussed earlier in this chapter, evidence exists that companies successfully executed wash trades over ICE by restricting the credit of companies not participating in the wash trading scheme. This ensured that competitors could not execute trades on offers placed on ICE that were intended for a specific company. A filter that monitors credit changes for corrupt reasons could be used to help evaluate unusual patterns in credit changes.

Staff believes that electronic data that directly provide trading information and efficiently report instances of concern to FERC would provide an effective oversight capability w[illegible] minimal cost to the industry. FERC would be able to learn from [illegible]posure to the information, distinguish false positives, and follow up where concerns remain. The cost of implementing this type of sophisticated system is decreasing and would likely increase Staff's productivity dramatically.

Staff believes that self-monitoring and reporting requirements could be created that would mandate companies to disclose behaviors that fall within certain definitions or risk losing their certificate to trade gas. Under parts 284.284 and 284.402 of its regulations, the Commission issued blanket certificates for unbundled gas sales services and marketing services, respectively. Staff recommends a proceeding to decide if and to what extent regulations should be implemented that require reporting to avoid losing or affecting the rights granted under the blanket certificates.

An important fundamental principle about market design and market-based rates is that commodity pricing should reflect competitive market conditions and the minimization of trading costs. The market design should be "workably competitive." For example, it is difficult to see how a market trading structure in which a single firm (such as Enron) is a dominant player and operates the leading platform (EOL) would meet these competitive standards in light of the potential for rent extraction and information production to advantage the dominant firm. While this report should not be construed as requiring one specific and definitive microstructure design of the trading structure, it does point to some of the types of dimensions in which the efficiencies of the microstructure of trading can be enhanced. Our report emphasizes the importance of effective competition across platforms and market designs.

One of the ways in which markets would be less prone to manipulation is by an open architecture and transparent trading system.[49] It is striking that EOL participants lacked access to information about the book of limit orders, except for the quotes, including knowledge of the location of the competition. One of the problems in the EOL design is that public investors cannot identify the available pockets of liquidity from Enron and public investors, but yet Enron can. A fundamental aspect of this point concerns the asymmetric observability of information, such as the limit order book, rather than the lack of public information per se. Outsiders would have been especially reluctant to show their hand in light of this asymmetry in the structure of

[49]This would discourage manipulations through the trading process and by providing false trade information to producers of market indices.

information and the potential ability of counterparties (such as Enron) to exploit any informational advantage.

Regarding the informational advantage EOL provided to Enron, the markets have adjusted. Currently there are no successful one-to-many platforms. UBS, which took control of the EOL platform, recently announced that it would no longer provide a one-to-many service. Dynegy did the same with regard to its one-to-many platform, DynegyDirect. ICE and TradeSpark are currently operating the leading electronic exchanges and are relatively transparent many-to-many exchanges. Nevertheless, Staff has recommended in Chapter VII of this Report that the Commission condition blanket gas certificates and market-based rates to require that sellers who use these platforms ensure that the platforms have certain information and monitoring features.

X. Analysis of Allegation That Williams Energy Marketing & Trading Company Attempted To Corner the Market in California for January 2001 Gas

The Commission Staff investigated an allegation that appeared in *The New York Times* on June 2, 2002 that Williams Energy Marketing & Trading Company (Williams) attempted to corner the market for natural gas in California and increase prices for gas delivered in January 2001. Staff examined trade records and other information and documents that Williams provided. Staff concludes that the claims are unsubstantiated.

Williams Energy Marketing & Trading Company

Williams is an energy marketing and trading unit of The Williams Companies, a publicly traded, Tulsa-based firm that owns and operates natural gas pipelines, among other activities. Williams is engaged in the purchase, sale, and arranging of transportation of natural gas. The company also provides risk management services through a variety of financial instruments and structured transactions, including over-the-counter forwards and other energy-related derivatives.[1]

A major share of Williams' gas needs relates to tolling agreements that Williams has executed under which it provides gas to three electric generation facilities in southern California.[2] During the fall and winter of 2000–2001, in order to provide gas to these facilities Williams' power desk notified its gas cash desk of the gas volumes required for the next business day. The gas cash desk reviewed prior-day actual gas consumption to determine daily and month-to-date imbalance positions. On a day-ahead basis, the gas cash desk determined whether to physically buy or sell gas to meet its requirements based on (1) the amount of baseload gas already purchased, (2) the amount of expected gas flow on El Paso Natural Gas Company's pipeline serving southern California, and (3) daily pricing versus forward pricing (balance-of-the-month or next-month pricing), among other factors. The gas cash desk then made trades by telephone or online exchanges. On a same-day basis, the gas cash desk monitored intraday changes in gas demand

[1] See www.williams.com/productservices/index.jsp and yahoo.marketguide.com/MGI/busidesc.asp?target=/stocks/companyinformation/busidesc&Ticker=WMB.

[2] See the Capacity Sale and Tolling Agreement filed in Docket Nos. ER98-2184-004, ER98-2185-004, and ER98-2186-004. The Commission summarized the tolling agreement briefly in AES Huntington Beach, L.L.C., 87 FERC ¶ 61,221 at p. 61,877 (1999). Williams also has additional gas customers in southern California.

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and purchased or sold gas to stay within pipeline imbalance tolerances. Based on its view of market fundamentals and changes in gas requirements at the electric generation facilities subject to the tolling agreements, the gas cash desk might also have held an incremental position of long or short going into the following month.

The Allegation That Williams Tried To Corner the Market and Drive Up Prices in California

On June 2, 2002, *The New York Times* printed an article in which it quoted Jones Murphy, a former Williams employee. According to the article, Williams hired Mr. Murphy as the director of emerging products at Williams' headquarters in Tulsa, Oklahoma, to help manage the company's trading risks. The article states that Mr. Murphy was on Williams' trading floor in December 2000 when he heard a commotion at the desk of Blake Herndon, director of risk management. The article quotes Mr. Murphy as stating that he "went over to ask what was going on," and that "Blake laughed and said they were going to corner the market for natural gas and run it up for December closing, which means delivery in January."[3] The article further states that Mr. Murphy "thinks that an examination of trading records would show that the company succeeded in driving up natural gas prices in California."[4]

In the article, Mr. Herndon denies Mr. Murphy's allegation. Mr. Herndon is quoted as stating that "[i]t is comical to think that anyone could corner the gas market in California. I think this shows the lack of understanding of how these markets work."[5] William Hobbs, president of Williams, is also quoted as denying Mr. Murphy's statement. Mr. Hobbs stated that "there has been any number of investigations, and Williams has fully cooperated." He also stated in the article that "[w]e have provided piles and piles of documents, and no one has come back and said that Williams has done anything wrong."[6]

[3] Banerjee, Neela, "A Collision on Risks of Energy Trading," *The New York Times* (June 2, 2002) at Business section, p. 1.
[4] Id.
[5] Id.
[6] Id.

The Commission Staff's Investigation of the Allegation

On June 5, 2002, counsel for Williams stated in a letter to the Commission Staff that it welcomed an independent review of its gas trading data to permit an evaluation of the allegation. Staff requested from Williams, and Williams voluntarily provided, a substantial volume of data and documents, including records of physical and financial transactions executed in the fall and winter of 2000–2001, cash book summary reports for gas, daily position reports, and mark-to-market values.

As discussed above, the allegation is that Williams drove up prices in an effort to corner the market for monthly gas in California with delivery in January 2001. Monthly gas is traded over a span of time that can begin several months in advance of the month of delivery. Peak trading typically occurs in the weeks preceding the month of delivery and ends when the month of delivery begins. Positions taken by traders are measured in terms of gas quantities, such as MMBtu or NYMEX contracts. Position reports typically include relevant information such as the geographic location of the gas to be traded and the month of delivery. Position statements provide information about a trading desk's position by time and location, and profit and loss statements identify profits and losses associated with those positions.

As a general matter, a market participant attempts to corner a market by accumulating a long position, which in the context of this investigation would mean entering contracts to purchase physical gas. To successfully corner a market, the market participant's long position must represent a substantial portion of available supply. When prices have peaked, the market participant liquidates its position at profits that reflect an exercise of market power. By accumulating a substantial position, the market participant can exert market power by raising the price it can secure for its supply.

Conclusion of the Commission Staff's Investigation

For Williams to corner the market for physical gas, it would have needed to purchase gas in volumes that greatly exceeded the requirements of Williams' gas customers. We do not see evidence of this purchasing activity on a day-to-day or even an intraday basis. In November 2000, Williams' customers' physical needs pursuant to its tolling agreements were 10,274,209 Bcf, and Williams purchased

10,701,353 Bcf. In December 2000, Williams' customers' physical needs pursuant to its tolling agreements were 10,905,316 Bcf, and Williams purchased 11,143,809 Bcf. Finally, in January 2001, Williams' customers' physical needs pursuant to its tolling agreements were 14,247,195 Bcf, and Williams purchased 12,681,667 Bcf. These data show that Williams did not purchase substantially more gas than it needed to meet its customers' physical needs. In fact, the amounts that Williams purchased above its needs represent less than 1 percent of the gas market in southern California.

In November and December 2000 and January 2001, Williams' natural gas purchases represented approximately 4, 5, and 6 percent, respectively, of the total demand for Southern California Gas Company and Pacific Gas and Electric Company. During November and December 2000, Williams' natural gas purchases represented approximately 10 percent of the total Southern California Gas Company demand. These data place into perspective the dimension of Williams' physical activity in the relevant time period. While not insubstantial, it appears to be too small to constitute a corner-the-market strategy.

Williams' cash desk began the month of November for southern California short approximately 43,000 MMBtu/d at approximately $5.20. Gas prices increased throughout the month, from $5.20 to $17.99. Overall, the gas cash desk incurred a loss for November 2000 on physical gas transactions. In December 2000, the gas cash desk began the month long for southern California approximately 67,000 MMBtu/d at approximately $14. *Gas Daily* index prices averaged approximately $25 throughout the month. Overall, the cash desk incurred a gain for December 2000 of less than $35 million on physical gas transactions. Williams' profit and loss activity in the 2 months preceding January indicates a level of profits that is not large relative to the size of the gas market in southern California.

In addition to profiting by cornering physical gas, we might also expect to see large positions taken in the financial markets in anticipation of increasing gas prices. However, we do not see evidence of this activity. Williams' largest long financial position in January 2001 SoCal gas was 80,000 MMBtu/d. This position was active during November 2000. It was small relative to the volume of gas that Williams needed to purchase to meet its customers' needs. The fact that Williams' financial position was far smaller than its physical position indicates that Williams did not have a strong belief that prices would rise.

Williams' gross mark-to-market margin for the forward southern California basis January 2001 contract also does not reflect a strategy to corner the market. Williams recorded a gain of approximately $3.5 million in November 2000 and less than $1 million in December 2000. Williams' cumulative gross cash margin for the gas cash desk for southern California for January 2001 was a gain of less than $12 million.

Based on our review of data, information, and documents that Williams provided, the Commission Staff concludes that the allegations that Williams cornered the market in southern California for January 2001 natural gas and drove up natural gas prices in southern California during the fall and winter of 2000–2001 are unsubstantiated.

Appendix II-A: Supporting Tables for Analysis of Reliant Natural Gas Transactions

Table II-A1. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Gross Trading (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[1]
1	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	3,705,000
2	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	2,280,000
3	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	1,824,000
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	1,740,000
5	SoCal Topock EPNG	12/8/00	Reliant Energy Services, Inc.	1,440,000
6	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	1,420,000
7	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	1,400,000
8	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	1,354,000
9	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	1,230,000
10	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	1,215,000
11	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	1,110,000
12	SoCal Topock EPNG	1/5/01	Reliant Energy Services, Inc.	1,020,000
13	SoCal Topock EPNG	12/22/00	Reliant Energy Services, Inc.	925,000
14	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	911,000
15	EPNG SoCal Ehrenberg	3/23/01	Reliant Energy Services, Inc.	900,000
16	SoCal Topock EPNG	12/6/00	Reliant Energy Services, Inc.	803,000
17	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	780,000
18	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	773,000
19	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	730,000
20	SoCal Topock EPNG	11/17/00	Aquila Energy Marketing Corporation	720,000
21	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	710,000
22	SoCal Topock EPNG	12/7/00	Reliant Energy Services, Inc.	700,000
23	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	670,000
24	SoCal Topock EPNG	2/23/01	Reliant Energy Services, Inc.	630,000
25	SoCal Topock EPNG	2/9/01	Reliant Energy Services, Inc.	622,500
26	PG&E Ctygte Pool	5/25/01	Duke Energy Trading and Marketing, L.L.C.	600,000
27	SoCal Topock EPNG	11/22/00	Southern California Gas Company	600,000
28	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	574,000
29	SoCal Topock EPNG	12/12/00	Reliant Energy Services, Inc.	570,000
30	SoCal Topock EPNG	1/12/01	Dynegy Marketing and Trade	560,000
31	PG&E Ctygte Pool	5/4/01	Duke Energy Trading and Marketing, L.L.C.	555,000

[1]Gross quantity is adjusted for the duration of the contract: a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity, while a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[1]
32	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	550,000
33	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	525,000
34	PG&E Ctygte Pool	11/10/00	Duke Energy Trading and Marketing, L.L.C.	525,000
35	SoCal Topock EPNG	12/15/00	Dynegy Marketing and Trade	525,000
36	SoCal Topock EPNG	1/26/01	Duke Energy Trading and Marketing, L.L.C.	525,000
37	SoCal Topock EPNG	1/12/01	Duke Energy Trading and Marketing, L.L.C.	520,000
38	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	513,000
39	SoCal Topock EPNG	11/30/00	Reliant Energy Services, Inc.	502,000
40	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	490,000

Table II-A2. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Net Purchases (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[2]	Net Purchases (MMBtu)
1	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	1,420,000	1,380,000
2	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	1,824,000	1,356,000
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	3,705,000	1,085,000
4	SoCal Topock EPNG	1/5/01	Reliant Energy Services, Inc.	1,020,000	1,020,000
5	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	1,400,000	900,000
6	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	2,280,000	780,000
7	SoCal Topock EPNG	12/22/00	Reliant Energy Services, Inc.	925,000	775,000
8	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	1,230,000	690,000
9	PG&E Ctygte Pool	5/25/01	Duke Energy Trading and Marketing, L.L.C.	600,000	600,000
10	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	730,000	570,000
11	SoCal Topock EPNG	1/12/01	Dynegy Marketing and Trade	580,000	580,000
12	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	773,000	557,000
13	PG&E Ctygte Pool	5/4/01	Duke Energy Trading and Marketing, L.L.C.	555,000	555,000
14	SoCal Topock EPNG	12/8/00	Reliant Energy Services, Inc.	1,440,000	540,000
15	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	1,215,000	495,000
16	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	780,000	480,000
17	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	490,000	470,000
18	SoCal Topock EPNG	12/18/00	Reliant Energy Services, Inc.	480,000	480,000
19	SoCal Topock EPNG	2/23/01	Reliant Energy Services, Inc.	630,000	450,000
20	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	445,000	445,000
21	SoCal Topock EPNG	4/27/01	Reliant Energy Services, Inc.	420,000	420,000
22	SoCal Topock EPNG	12/12/00	Reliant Energy Services, Inc.	570,000	410,000
23	SoCal Topock EPNG	2/12/01	Reliant Energy Services, Inc.	470,000	410,000
24	SoCal Topock EPNG	2/14/01	Reliant Energy Services, Inc.	430,000	410,000
25	PG&E Ctygte Pool	11/17/00	Duke Energy Trading and Marketing, L.L.C.	465,000	405,000
26	SoCal Topock EPNG	2/22/01	Reliant Energy Services, Inc.	470,000	390,000
27	Waha	11/3/00	Aquila Energy Marketing Corporation	450,000	390,000
28	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	390,000	390,000
29	PG&E Ctygte Pool	1/12/01	Duke Energy Trading and Marketing, L.L.C.	480,000	380,000
30	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	400,000	380,000
31	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	380,000	380,000
32	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	710,000	370,000

[2]Gross quantity and net purchases are adjusted for the duration of the contract: buying a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net purchases, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net purchases. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[2]	Net Purchases (MMBtu)
33	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	550,000	370,000
34	SoCal Topock EPNG	12/29/00	Reliant Energy Services, Inc.	440,000	360,000
35	SoCal Topock EPNG	1/2/01	Reliant Energy Services, Inc.	340,000	340,000
36	PG&E Ctygte Pool	1/19/01	Duke Energy Trading and Marketing, L.L.C.	450,000	330,000
37	PG&E Ctygte Pool	11/3/00	Duke Energy Trading and Marketing, L.L.C.	390,000	330,000
38	SoCal Topock EPNG	2/15/01	Reliant Energy Services, Inc.	330,000	330,000
39	SoCal Topock EPNG	2/20/01	Reliant Energy Services, Inc.	345,000	325,000
40	SoCal Topock EPNG	12/14/00	Reliant Energy Services, Inc.	358,000	322,000

Table II-A3. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Daily Net Sales (continued on next page)

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[3]	Net Sales (MMBtu)
1	SoCal Topock EPNG	11/22/00	Southern California Gas Company	600,000	600,000
2	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	525,000	525,000
3	SoCal Topock EPNG	12/15/00	Dynegy Marketing and Trade	525,000	525,000
4	SoCal Topock EPNG	12/15/00	Southern California Gas Company	484,638	484,638
5	SoCal Topock EPNG	3/23/01	El Paso Merchant Energy, L.P.	480,000	480,000
6	SoCal Topock EPNG	12/22/00	Dynegy Marketing and Trade	450,000	450,000
7	SoCal Topock EPNG	2/23/01	El Paso Merchant Energy, L.P.	442,500	442,500
8	SoCal Topock EPNG	1/12/01	Duke Energy Trading and Marketing, L.L.C.	520,000	440,000
9	SoCal Topock EPNG	1/5/01	El Paso Merchant Energy, L.P.	435,000	435,000
10	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	420,000	420,000
11	EPNG SoCal Ehrenberg	3/9/01	El Paso Merchant Energy, L.P.	396,000	396,000
12	SoCal Topock EPNG	12/1/00	Dynegy Marketing and Trade	390,000	390,000
13	SoCal Topock EPNG	12/8/00	Dynegy Marketing and Trade	390,000	390,000
14	SoCal Topock EPNG	2/16/01	El Paso Merchant Energy, L.P.	380,000	380,000
15	EPNG SoCal Ehrenberg	3/2/01	El Paso Merchant Energy, L.P.	380,000	380,000
16	SoCal Topock EPNG	11/22/00	Duke Energy Trading and Marketing, L.L.C.	350,000	350,000
17	SoCal Topock EPNG	1/26/01	Duke Energy Trading and Marketing, L.L.C.	525,000	345,000
18	SoCal Topock EPNG	11/3/00	Duke Energy Trading and Marketing, L.L.C.	345,000	345,000
19	SoCal Topock EPNG	11/17/00	Aquila Energy Marketing Corporation	720,000	330,000
20	EPNG SoCal Ehrenberg	3/30/01	El Paso Merchant Energy, L.P.	330,000	330,000
21	EPNG SoCal Ehrenberg	5/18/01	Reliant Energy Services, Inc.	330,000	330,000
22	PG&E Ctygte Pool	3/2/01	Duke Energy Trading and Marketing, L.L.C.	330,000	330,000
23	SoCal Topock EPNG	11/22/00	Williams Energy Marketing & Trading Company	325,000	325,000
24	PG&E Ctygte Pool	1/12/01	El Paso Merchant Energy, L.P.	300,000	300,000
25	SoCal Topock EPNG	11/10/00	Aquila Energy Marketing Corporation	300,000	300,000
26	SoCal Topock EPNG	12/22/00	Aquila Energy Marketing Corporation	300,000	300,000
27	EPNG SoCal Ehrenberg	3/16/01	El Paso Merchant Energy, L.P.	285,000	285,000
28	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	285,000	285,000
29	SoCal Topock EPNG	1/19/01	Duke Energy Trading and Marketing, L.L.C.	285,000	285,000
30	SoCal Topock EPNG	1/12/01	Williams Energy Marketing & Trading Company	280,000	280,000
31	PG&E Ctygte Pool	1/19/01	El Paso Merchant Energy, L.P.	270,000	270,000
32	SoCal Topock EPNG	2/2/01	El Paso Merchant Energy, L.P.	270,000	270,000

[3]Gross quantity and net sales are adjusted for the duration of the contract: selling a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net sales, while selling a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net sales. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Rank	Location	Transaction Date	Counterparty	Gross Quantity (MMBtu)[3]	Net Sales (MMBtu)
33	PG&E Citygate Pool	5/25/01	Calpine Energy Services, L.P.	260,000	260,000
34	SoCal Topock EPNG	1/5/01	Duke Energy Trading and Marketing, L.L.C.	255,000	255,000
35	SoCal Topock EPNG	2/2/01	Duke Energy Trading and Marketing, L.L.C.	255,000	255,000
36	PG&E Citygate Pool	11/10/00	Aquila Energy Marketing Corporation	480,000	240,000
37	EPNG SoCal Ehrenberg	3/2/01	Southern California Gas Company	240,000	240,000
38	EPNG SoCal Ehrenberg	4/6/01	Reliant Energy Services, Inc.	240,000	240,000
39	PG&E Citygate Pool	4/27/01	Enron Energy Services, Inc.	240,000	240,000
40	SoCal Topock EPNG	12/8/00	Aquila Energy Marketing Corporation	240,000	240,000

Table II-A4. EOL Topock and Ehrenberg Gas Spot Trades, November 2000 – June 2001, Largest Net Sellers to Enron by Month (continued on next page)

Transaction Month	Rank Within Month	Counterparty	Counterparty Net Sales (MMBtu)[4]	Gross Volume (MMBtu)
Nov-00	1	Aquila Energy Marketing Corporation	2,615,000	3,575,000
	2	Duke Energy Trading and Marketing, L.L.C.	2,210,000	2,720,000
	3	Southern California Gas Company	1,375,000	1,405,000
	4	San Diego Gas & Electric Company	595,000	595,000
	5	PG&E Energy Trading-Gas Corporation	555,000	785,000
Dec-00	1	Dynegy Marketing and Trade	3,545,000	3,605,000
	2	Aquila Energy Marketing Corporation	2,110,000	2,140,000
	3	Southern California Gas Company	1,807,638	1,827,638
	4	Mirant Americas Energy Marketing, L.P.	1,381,000	1,381,000
	5	Enserco Energy, Inc.	917,000	917,000
Jan-01	1	Duke Energy Trading and Marketing, L.L.C.	2,720,850	3,280,850
	2	Williams Energy Marketing & Trading Company	1,020,000	1,020,000
	3	Coral Energy Resources, L.P.	872,708	892,708
	4	El Paso Merchant Energy, L.P.	741,000	1,821,000
	5	Aquila Energy Marketing Corporation	439,000	791,000
Feb-01	1	El Paso Merchant Energy, L.P.	2,806,000	3,086,000
	2	Duke Energy Trading and Marketing, L.L.C.	1,454,000	1,884,000
	3	Aquila Energy Marketing Corporation	595,000	835,000
	4	Mirant Americas Energy Marketing, L.P.	524,000	554,000
	5	Southern California Gas Company	332,500	332,500
Mar-01	1	El Paso Merchant Energy, L.P.	5,484,000	5,624,000
	2	Southern California Gas Company	790,000	1,080,000
	3	Aquila Energy Marketing Corporation	641,000	1,037,000
	4	Texaco Natural Gas Inc.	391,000	391,000
	5	Burlington Resources Trading Inc.	215,808	215,808

[4]Net sales and gross quantity are adjusted for the duration of the contract: selling a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the net sales and gross quantity, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the net sales and gross quantity. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Transaction Month	Rank Within Month	Counterparty	Counterparty Net Sales (MMBtu)[4]	Gross Volume (MMBtu)
Apr-01	1	El Paso Merchant Energy, L.P.	2,653,488	2,763,488
	2	Duke Energy Trading and Marketing, L.L.C.	1,037,754	1,177,754
	3	Mirant Americas Energy Marketing, L.P.	944,767	944,767
	4	Coral Energy Resources, L.P.	941,000	979,000
	5	Southern California Gas Company	500,000	520,000
May-01	1	El Paso Merchant Energy, L.P.	2,114,222	2,634,222
	2	Enserco Energy, Inc.	530,000	570,000
	3	Calpine Energy Services, L.P.	380,500	878,500
	4	PG&E Energy Trading-Gas Corporation	169,598	169,598
	5	AEP Energy Services, Inc.	144,022	864,022
Jun-01	1	Duke Energy Trading and Marketing, L.L.C.	868,648	1,158,648
	2	Mirant Americas Energy Marketing, L.P.	601,238	601,238
	3	El Paso Merchant Energy, L.P.	566,336	1,056,336
	4	Aquila Energy Marketing Corporation	523,162	749,262
	5	BP Energy Company	392,500	432,500
Total	1	El Paso Merchant Energy, L.P.	14,365,046	16,985,046
	2	Duke Energy Trading and Marketing, L.L.C.	7,486,100	12,420,100
	3	Aquila Energy Marketing Corporation	7,268,162	10,414,262
	4	Southern California Gas Company	5,014,188	6,134,188
	5	Mirant Americas Energy Marketing, L.P.	4,202,889	4,312,889
	6	Coral Energy Resources, L.P.	2,832,665	4,448,623
	7	Williams Energy Marketing & Trading Company	2,566,134	4,336,134
	8	Dynegy Marketing and Trade	1,853,013	11,778,971
	9	Enserco Energy, Inc.	1,808,500	2,398,500
	10	BP Energy Company	1,696,000	2,491,000

Table II-A5. EOL Western Gas Spot Trades, November 2000 – June 2001, Counterparties With the Greatest Monthly Net Purchases

Rank	Location	Transaction Month	Counterparty	Gross Quantity (MMBtu)[5]	Net Purchases (MMBtu)
1	SoCal Topock EPNG	December 2000	Reliant Energy Services, Inc.	15,296,000	8,024,000
2	SoCal Topock EPNG	February 2001	Reliant Energy Services, Inc.	11,422,500	7,227,500
3	SoCal Topock EPNG	January 2001	Reliant Energy Services, Inc.	8,438,350	6,131,850
4	PG&E Ctygte Pool	May 2001	Duke Energy Trading and Marketing, L.L.C.	2,968,475	2,478,475
5	SoCal Topock EPNG	November 2000	Reliant Energy Services, Inc.	5,172,000	2,188,000
6	Opal	April 2001	BP Energy Company	2,381,266	2,044,942
7	SoCal Topock EPNG	May 2001	Reliant Energy Services, Inc.	1,934,479	1,914,479
8	PG&E Ctygte Pool	January 2001	Duke Energy Trading and Marketing, L.L.C.	2,815,000	1,885,000
9	PG&E Ctygte Pool	November 2000	Duke Energy Trading and Marketing, L.L.C.	3,075,000	1,735,000
10	SoCal Topock EPNG	June 2001	Reliant Energy Services, Inc.	2,835,059	1,542,059
11	Waha	March 2001	BP Energy Company	1,485,000	1,485,000
12	EPNG SoCal Ehrenberg	May 2001	Sempra Energy Trading Corp.	1,295,000	1,275,000
13	Opal	December 2000	Dynegy Marketing and Trade	1,285,000	1,275,000
14	PGT Malin	November 2000	Dynegy Marketing and Trade	1,480,000	1,255,000
15	PG&E Topock	June 2001	PG&E Energy Trading-Gas Corporation	1,243,030	1,199,030
16	PG&E Ctygte Pool	April 2001	Mirant Americas Energy Marketing, L.P.	1,085,000	1,085,000
17	PG&E Ctygte Pool	June 2001	Duke Energy Trading and Marketing, L.L.C.	1,599,500	1,059,500
18	SoCal Topock EPNG	January 2001	Dynegy Marketing and Trade	1,384,000	1,034,000
19	Waha	April 2001	BP Energy Company	980,000	980,000
20	SoCal Topock EPNG	April 2001	Reliant Energy Services, Inc.	1,570,000	950,000
21	Waha	February 2001	BP Energy Company	955,000	935,000
22	EPNG SoCal Ehrenberg	May 2001	Reliant Energy Services, Inc.	2,205,000	915,000
23	PG&E Ctygte Pool	April 2001	Duke Energy Trading and Marketing, L.L.C.	1,290,000	880,000
24	PG&E Ctygte Pool	November 2000	Coast Energy Canada, Inc.	1,055,000	855,000
25	Waha	June 2001	Duke Energy Field Services Marketing, LLC	835,000	835,000
26	Opal	November 2000	Dynegy Marketing and Trade	910,000	820,000
27	PG&E Ctygte Pool	November 2000	Pacific Gas & Electric Company	820,000	820,000
28	Opal	November 2000	Cook Inlet Energy Supply L.L.C.	1,985,000	795,000
29	PG&E Ctygte Pool	March 2001	Duke Energy Trading and Marketing, L.L.C.	1,815,000	675,000
30	PGT Malin	February 2001	Enron Energy Services, Inc.	655,000	655,000
31	EPNG SoCal Ehrenberg	June 2001	Sempra Energy Trading Corp.	677,500	637,500
32	Opal	December 2000	Barrett Resources Corporation	715,000	615,000

[5]Gross quantity and net purchases are adjusted for the duration of the contract: buying a 1-day spot contract for 10,000 MMBtu/d would contribute 10,000 MMBtu to the gross quantity and net purchases, while buying a 3-day weekend spot contract for 10,000 MMBtu/d would contribute 30,000 MMBtu to the gross quantity and net sales. Almost all spot contracts are for 1 or 3 days, although contracts for holiday weekends are generally for 4 days and contracts for the Thanksgiving weekend are for 5 days.

Table II-A6. Trading in EOL Spot Gas, Topock and Ehrenberg Points Only, November 2000 – June 2001, Busiest EOL Trading Days for Individual Counterparties

Rank	Transaction Date	Counterparty	Number of Transactions
1	1/31/01	Reliant Energy Services, Inc.	174
2	12/11/00	Reliant Energy Services, Inc.	136
3	2/2/01	Reliant Energy Services, Inc.	124
4	12/5/00	Reliant Energy Services, Inc.	89
5	12/1/00	Reliant Energy Services, Inc.	76
6	12/13/00	Reliant Energy Services, Inc.	74
7	1/3/01	Reliant Energy Services, Inc.	73
8	12/6/00	Reliant Energy Services, Inc.	72
9	12/7/00	Reliant Energy Services, Inc.	71
10	2/13/01	Reliant Energy Services, Inc.	71
11	12/19/00	Reliant Energy Services, Inc.	67
12	3/23/01	Reliant Energy Services, Inc.	66
13	6/11/01	Reliant Energy Services, Inc.	61
14	12/15/00	Reliant Energy Services, Inc.	58
15	12/12/00	Reliant Energy Services, Inc.	57
16	2/1/01	Reliant Energy Services, Inc.	55
17	12/4/00	Reliant Energy Services, Inc.	52
18	6/13/01	Reliant Energy Services, Inc.	52
19	11/30/00	Reliant Energy Services, Inc.	51
20	11/27/00	Reliant Energy Services, Inc.	48
21	12/8/00	Reliant Energy Services, Inc.	48
22	12/18/00	Reliant Energy Services, Inc.	48
23	2/12/01	Reliant Energy Services, Inc.	47
24	2/22/01	Reliant Energy Services, Inc.	47
25	5/22/01	Reliant Energy Services, Inc.	47
26	2/14/01	Reliant Energy Services, Inc.	45
27	1/16/01	Reliant Energy Services, Inc.	44
28	1/26/01	Reliant Energy Services, Inc.	42
29	3/2/01	Reliant Energy Services, Inc.	42
30	5/10/01	Reliant Energy Services, Inc.	42

Table II-A7. Purchases and Sales of at Least 100,000 MMBtu/d by Counterparty and Location (Topock and Ehrenberg Combined)

Counterparty	Location	Transaction Date	Number of Transactions	Sell (MMBtu/d)	Buy (MMBtu/d)	Gross Volume (MMBtu/d)
Reliant Energy Services, Inc.	SoCal Topock	11/1/00	21	100,000	100,000	200,000
Duke Energy Trading and Marketing, LLC	PG&E Ctygte	11/9/00	34	125,000	185,000	310,000
Reliant Energy Services, Inc.	SoCal Topock	11/13/00	40	190,000	200,000	390,000
Aquila Energy Marketing Corporation	SoCal Topock	11/16/00	28	170,000	100,000	270,000
Reliant Energy Services, Inc.	SoCal Topock	11/30/00	51	182,000	320,000	502,000
Reliant Energy Services, Inc.	SoCal Topock	12/1/00	76	250,000	510,000	760,000
Reliant Energy Services, Inc.	SoCal Topock	12/4/00	52	203,000	310,000	513,000
Reliant Energy Services, Inc.	SoCal Topock	12/5/00	89	311,000	600,000	911,000
Reliant Energy Services, Inc.	SoCal Topock	12/6/00	72	313,000	490,000	803,000
Reliant Energy Services, Inc.	SoCal Topock	12/7/00	71	220,000	480,000	700,000
Reliant Energy Services, Inc.	SoCal Topock	12/8/00	48	150,000	330,000	480,000
Reliant Energy Services, Inc.	SoCal Topock	12/11/00	136	554,000	800,000	1,354,000
Reliant Energy Services, Inc.	SoCal Topock	12/13/00	74	108,000	665,000	773,000
Reliant Energy Services, Inc.	SoCal Topock	12/19/00	67	200,000	470,000	670,000
Reliant Energy Services, Inc.	SoCal Topock	1/31/01	174	730,000	1,010,000	1,740,000
Reliant Energy Services, Inc.	SoCal Topock	2/2/01	124	440,000	795,000	1,235,000
Reliant Energy Services, Inc.	SoCal Topock	2/13/01	71	170,000	540,000	710,000
Reliant Energy Services, Inc.	SoCal Topock	2/28/01	33	120,000	210,000	330,000
Reliant Energy Services, Inc.	SoCal Topock	3/1/01	31	155,000	160,000	315,000
Reliant Energy Services, Inc.	SoCal Topock	3/2/01	42	120,000	285,000	405,000
Reliant Energy Services, Inc.	SoCal Topock	3/20/01	27	110,000	160,000	270,000
Reliant Energy Services, Inc.	SoCal Topock	3/22/01	23	130,000	100,000	230,000
Reliant Energy Services, Inc.	SoCal Topock	3/23/01	66	320,000	350,000	670,000
Reliant Energy Services, Inc.	SoCal Topock	4/3/01	22	120,000	100,000	220,000
Reliant Energy Services, Inc.	SoCal Topock	6/11/01	61	224,000	400,000	624,000
Reliant Energy Services, Inc.	SoCal Topock	6/13/01	52	110,000	379,479	489,479

Table II-A8. December 2000 Price Chart, *Gas Daily* Index and EOL Prices With Churn Day Indication

Transaction Date	Contracted Flow Date or Flow Period	Reliant Gross Volume (MMBtu/d)	Gas Daily Midpoint Price ($/MMBtu)	EOL High ($/MMBtu)	EOL Low ($/MMBtu)	Weighted Price ($/MMBtu)	EOL Opening Price ($/MMBtu)	EOL Closing Price ($/MMBtu)	Reliant Churn Day
11/30/00	12/1/00	502,000	18.90	20.25	16.50	18.89	17.00	18.25	Yes
12/1/00	12/2 – 12/4/00	760,000	18.50	20.25	17.00	18.80	18.50	19.25	Yes
12/4/00	12/5/00	513,000	21.61	23.25	19.00	21.80	19.00	21.50	Yes
12/5/00	12/6/00	911,000	26.80	28.00	23.25	26.57	23.25	28.00	Yes
12/6/00	12/7/00	803,000	36.25	41.00	33.00	38.05	34.50	33.00	Yes
12/7/00	12/8/00	700,000	42.02	53.00	32.00	43.19	45.00	38.00	Yes
12/8/00	12/9 – 12/11/00	480,000	54.66	59.00	42.00	55.42	42.00	58.00	Yes
12/11/00	12/12/00	1,354,000	59.42	66.00	34.00	59.19	58.00	50.00	Yes
12/12/00	12/13/00	570,000	32.75	47.00	20.00	31.80	47.00	26.00	
12/13/00	12/14/00	773,000	20.26	24.00	14.00	20.16	22.00	19.00	Yes
12/14/00	12/15/00	358,000	19.03	24.00	15.00	19.23	16.00	15.00	
12/15/00	12/16 – 12/18/00	608,000	17.06	19.50	14.00	16.88	17.00	18.00	
12/18/00	12/19/00	480,000	20.39	22.50	17.00	20.52	17.00	19.50	
12/19/00	12/20/00	670,000	19.56	23.00	15.00	20.11	21.00	17.00	Yes
12/20/00	12/21/00	400,000	20.36	23.00	19.00	20.91	19.00	21.50	
12/21/00	12/22/00	335,000	18.98	22.00	18.00	18.95	22.00	18.00	
12/22/00	12/23 – 12/27/00	185,000	18.78	19.00	17.00	17.98	18.50	18.50	
12/27/00	12/28/00	220,000	16.64	18.50	15.50	16.76	18.50	15.50	
12/28/00	12/29 – 12/31/00	100,000	14.41	15.50	14.20	14.62	14.50	14.50	

Table II-A9. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Trades Within a Clock Minute[6] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Number of Transactions
1	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	16
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	15
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
5	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
6	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	12
7	PGT Malin	5/10/01	Enserco Energy, Inc.	11
8	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
9	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	11
10	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
11	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	10
12	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	10
13	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	10
14	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	10
15	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
16	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	9
17	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	9
18	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	9
20	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	9
21	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	9
22	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	9
23	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
24	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
25	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
26	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	9
27	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	9
28	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9
29	PG&E Ctygte Pool	4/26/01	Enron Energy Services, Inc.	8
30	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
31	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
32	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
33	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
34	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	8
35	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	8
36	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	8

[6]A clock minute is defined as starting at, for example, 8:51:00 and extending to 8:51:59.

Rank	Location	Transaction Date	Counterparty	Number of Transactions
37	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
38	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	8
39	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	8
40	SoCal Topock EPNG	2/16/01	Reliant Energy Services, Inc.	8

Table II-A10. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Trades Within 5 Clock Minutes[7] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Number of Transactions
1	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	49
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	39
3	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	34
4	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	32
5	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	25
6	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	25
7	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	24
8	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	23
9	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	23
10	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	22
11	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	21
12	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	21
13	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	21
14	SoCal Topock EPNG	11/17/00	Reliant Energy Services, Inc.	20
15	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	20
16	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	20
17	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	20
18	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	20
19	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	19
20	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	19
21	SoCal Topock EPNG	12/20/00	Reliant Energy Services, Inc.	19
22	SoCal Topock EPNG	2/22/01	Reliant Energy Services, Inc.	19
23	SoCal Topock EPNG	12/4/00	Reliant Energy Services, Inc.	18
24	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	18
25	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	18
26	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	18
27	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	18
28	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	18
29	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	17
30	SoCal Topock EPNG	1/17/01	Reliant Energy Services, Inc.	17
31	SoCal Topock EPNG	11/13/00	Reliant Energy Services, Inc.	16
32	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	16
33	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	15
34	SoCal Topock EPNG	12/13/00	Reliant Energy Services, Inc.	15
35	SoCal Topock EPNG	12/15/00	Reliant Energy Services, Inc.	15

[7] A period of 5 clock minutes is defined as starting at, for example, 8:51:00 and extending to 8:55:59.

Rank	Location	Transaction Date	Counterparty	Number of Transactions
36	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	15
37	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
38	PGT Malin	5/10/01	Enserco Energy, Inc.	14
39	SoCal Topock EPNG	11/22/00	Reliant Energy Services, Inc.	14
40	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	14

Table II-A11. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive Transactions by One Firm[9] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	43
2	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	34
3	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	23
4	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	22
5	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	20
6	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	18
7	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	16
8	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	16
9	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	15
10	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
11	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	14
12	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	14
13	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	14
14	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
15	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	13
16	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	13
17	Waha	3/16/01	BP Energy Company	13
18	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	12
19	Waha	3/19/01	BP Energy Company	12
20	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
21	SoCal Topock EPNG	2/5/01	El Paso Merchant Energy, L.P.	11
22	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
23	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
24	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
25	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	11
26	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	11
27	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	10
28	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	10
29	EPNG SoCal Ehrenberg	4/5/01	Reliant Energy Services, Inc.	10
30	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	10
31	EPNG SoCal Ehrenberg	3/8/01	El Paso Merchant Energy, L.P.	10
32	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	10
33	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	10
34	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	10

[9]These are the longest sequences of transactions for spot gas at a single location that are buy or sell transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
35	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
36	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	10
37	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	10
38	EPNG SoCal Ehrenberg	3/26/01	Reliant Energy Services, Inc.	9
39	EPNG SoCal Ehrenberg	3/2/01	Reliant Energy Services, Inc.	9
40	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9

Table II-A12. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive "Buy" Transactions By One Firm[9] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	SoCal Topock EPNG	11/27/00	Reliant Energy Services, Inc.	23
2	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	18
3	EPNG SoCal Ehrenberg	5/10/01	Reliant Energy Services, Inc.	16
4	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	13
5	SoCal Topock EPNG	1/4/01	Reliant Energy Services, Inc.	13
6	Waha	3/16/01	BP Energy Company	13
7	Waha	3/19/01	BP Energy Company	12
8	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	11
9	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
10	SoCal Topock EPNG	5/11/01	Reliant Energy Services, Inc.	10
11	SoCal Topock EPNG	2/21/01	Reliant Energy Services, Inc.	10
12	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	10
13	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	10
14	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	10
15	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	9
16	SoCal Topock EPNG	4/27/01	Reliant Energy Services, Inc.	9
17	SoCal Topock EPNG	2/12/01	Reliant Energy Services, Inc.	9
18	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	1/26/01	Reliant Energy Services, Inc.	9
20	SoCal Topock EPNG	1/25/01	Reliant Energy Services, Inc.	9
21	SoCal Topock EPNG	1/18/01	Reliant Energy Services, Inc.	9
22	SoCal Topock EPNG	1/16/01	Reliant Energy Services, Inc.	9
23	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	9
24	SoCal Topock EPNG	11/21/00	Reliant Energy Services, Inc.	9
25	Waha	11/6/00	Aquila Energy Marketing Corporation	9
26	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	8
27	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	8
28	SoCal Topock EPNG	4/23/01	Reliant Energy Services, Inc.	8
29	SoCal Topock EPNG	4/16/01	Dynegy Marketing and Trade	8
30	SoCal Topock EPNG	2/15/01	Reliant Energy Services, Inc.	8
31	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	8
32	SoCal Topock EPNG	2/1/01	Reliant Energy Services, Inc.	8
33	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
34	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8
35	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	8

[9]These are the longest sequences of transactions for spot gas at a single location that are buy transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
36	SoCal Topock EPNG	1/25/01	Reliant Energy Services, Inc.	8
37	SoCal Topock EPNG	1/22/01	Reliant Energy Services, Inc.	8
38	SoCal Topock EPNG	1/17/01	Reliant Energy Services, Inc.	8
39	SoCal Topock EPNG	1/3/01	Reliant Energy Services, Inc.	8
40	SoCal Topock EPNG	1/2/01	Reliant Energy Services, Inc.	8

Table II-A13. EOL Western Gas Spot Trades, November 2000 – June 2001, Most Consecutive "Sell" Transactions By One Firm[10] (continued on next page)

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
1	EPNG SoCal Ehrenberg	6/15/01	Reliant Energy Services, Inc.	14
2	SoCal Topock EPNG	2/5/01	El Paso Merchant Energy, L.P.	11
3	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	11
4	SoCal Topock EPNG	11/3/00	Aquila Energy Marketing Corporation	11
5	EPNG SoCal Ehrenberg	4/26/01	Reliant Energy Services, Inc.	10
6	EPNG SoCal Ehrenberg	4/11/01	Reliant Energy Services, Inc.	10
7	EPNG SoCal Ehrenberg	4/5/01	Reliant Energy Services, Inc.	10
8	EPNG SoCal Ehrenberg	3/23/01	El Paso Merchant Energy, L.P.	10
9	EPNG SoCal Ehrenberg	3/8/01	El Paso Merchant Energy, L.P.	10
10	SoCal Topock EPNG	6/11/01	Reliant Energy Services, Inc.	10
11	EPNG SoCal Ehrenberg	3/26/01	Reliant Energy Services, Inc.	9
12	SoCal Topock EPNG	6/13/01	Reliant Energy Services, Inc.	9
13	SoCal Topock EPNG	3/23/01	Reliant Energy Services, Inc.	9
14	SoCal Topock EPNG	3/21/01	El Paso Merchant Energy, L.P.	9
15	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	9
16	SoCal Topock EPNG	1/29/01	Aquila Energy Marketing Corporation	9
17	SoCal Topock EPNG	12/19/00	Reliant Energy Services, Inc.	9
18	SoCal Topock EPNG	12/5/00	Reliant Energy Services, Inc.	9
19	SoCal Topock EPNG	12/1/00	Reliant Energy Services, Inc.	9
20	EPNG SoCal Ehrenberg	5/23/01	BP Energy Company	8
21	EPNG SoCal Ehrenberg	3/27/01	El Paso Merchant Energy, L.P.	8
22	EPNG SoCal Ehrenberg	3/22/01	Reliant Energy Services, Inc.	8
23	PG&E Topock	4/2/01	El Paso Merchant Energy, L.P.	8
24	SoCal Topock EPNG	12/15/00	Southern California Gas Company	8
25	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
26	SoCal Topock EPNG	12/11/00	Reliant Energy Services, Inc.	8
27	SoCal Topock EPNG	11/20/00	Reliant Energy Services, Inc.	8
28	SoCal Topock EPNG	11/1/00	Dynegy Marketing and Trade	8
29	CIG Mainline	12/11/00	BP Energy Company	7
30	EPNG SoCal Ehrenberg	4/16/01	Reliant Energy Services, Inc.	7
31	EPNG SoCal Ehrenberg	3/29/01	Southern California Gas Company	7
32	EPNG SoCal Ehrenberg	3/16/01	El Paso Merchant Energy, L.P.	7
33	EPNG SoCal Ehrenberg	3/13/01	El Paso Merchant Energy, L.P.	7
34	PG&E Ctygte Pool	1/22/01	El Paso Merchant Energy, L.P.	7
35	PGT Malin	5/1/01	Enserco Energy, Inc.	7

[10]These are the longest sequences of transactions for spot gas at a single location that are sell transactions by a single firm.

Rank	Location	Transaction Date	Counterparty	Consecutive Transactions
36	SoCal Topock EPNG	2/13/01	Reliant Energy Services, Inc.	7
37	SoCal Topock EPNG	2/7/01	El Paso Merchant Energy, L.P.	7
38	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	7
39	SoCal Topock EPNG	2/2/01	Reliant Energy Services, Inc.	7
40	SoCal Topock EPNG	1/31/01	Reliant Energy Services, Inc.	7

Table II-A14. Reliant's Profit From EOL-Reliant Netting Agreement, Highest Daily Profit From the Netting Agreement ($100,000 or More)

		Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	Churn Day	Transactions	Volume (MMBtu)	Price	Transactions	Volume (MMBtu)	Price	Reliant's Net Buy From EOL	Profit From the Netting Agreement
12/11/00	Yes	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/08/00	Yes	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
03/01/01	Yes	15	155,000	$26.03	16	160,000	$22.43	5,000	$558,156
01/31/01	Yes	73	730,000	$14.21	101	1,010,000	$13.62	280,000	$431,267
02/13/01	Yes	17	170,000	$36.78	54	540,000	$34.30	370,000	$421,343
02/02/01	Yes	44	1,320,000	$16.24	80	2,385,000	$15.96	1,065,000	$369,726
12/05/00	Yes	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/01/00	Yes	25	750,000	$19.21	51	1,530,000	$18.75	780,000	$345,000
03/06/01	No	7	70,000	$30.07	6	60,000	$24.42	(10,000)	$339,286
11/17/00	No	1	150,000	$10.50	21	630,000	$8.30	480,000	$329,929
12/06/00	Yes	23	313,000	$38.68	49	490,000	$37.78	177,000	$282,285
11/30/00	Yes	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
03/02/01	Yes	12	360,000	$30.22	30	855,000	$29.46	495,000	$273,158
12/04/00	Yes	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/07/00	Yes	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
11/20/00	No	8	80,000	$13.75	7	70,000	$11.19	(10,000)	$179,250
02/23/01	No	3	90,000	$14.33	18	540,000	$12.38	450,000	$176,250
02/09/01	No	9	232,500	$15.95	13	390,000	$15.45	157,500	$115,529
12/19/00	Yes	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
19 Days	14 Churn Days	420	6,540,500		777	12,630,000		6,089,500	$8187,833

Total Profit on the Churn Days	$7,047,590	86.07%
Total Profit on the other Days	$1,140,243	13.93%

Table II-A15. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes, Highest Daily Profit From the Netting Agreement ($100,000 or More)

Transaction Date	Churn Day	Profit From the Netting Agreement	Average Buy Price		GasDaily SoCal Large Packages Midpoint Price Index
			Without the Netting Agreement	Applying Profit From the Netting Agreement, Assuming 60% Flow	
12/11/00	Yes	$1,622,025	$51.24	$46.85	$59.42
12/08/00	Yes	$1,584,545	$51.28	$49.32	$54.66
03/01/01	Yes	$558,156	N/A[11]	N/A[11]	$23.95
01/31/01	Yes	$431,267	$12.08	$11.05	$13.75
02/13/01	Yes	$421,343	$33.16	$32.40	$34.53
02/02/01	Yes	$369,726	$15.61	$15.38	$15.39
12/05/00	Yes	$350,617	$25.00	$24.19	$26.60
12/01/00	Yes	$345,000	$18.31	$18.01	$18.50
03/06/01	No	$339,286	N/A[12]	N/A[12]	$25.27
11/17/00	No	$329,929	$7.61	$7.15	$9.60
12/06/00	Yes	$282,265	$36.18	$35.12	$36.25
11/30/00	Yes	$280,313	$16.25	$14.90	$18.90
03/02/01	Yes	$273,158	$28.91	$28.54	$27.79
12/04/00	Yes	$233,919	$19.20	$17.74	$21.61
12/07/00	Yes	$186,000	$42.28	$41.81	$42.02
11/20/00	No	$179,250	N/A[12]	N/A[12]	$13.42
02/23/01	No	$176,250	$11.98	$11.72	$12.68
02/09/01	No	$115,529	$14.72	$14.23	$14.83
12/19/00	Yes	$109,255	$19.57	$19.30	$19.56

[11]On March 1, 2001, Reliant bought 160,000 MMBtu on EOL and sold back 155,000 MMBtu. The net purchase, 5,000 MMBtu, is very small relative to the gross volume (only 1.59 percent). The profit generated by the difference between the buy price and the sell price for the 155,000 MMBtu is $558,156.

[12]On March 6, 2001 and November 20, 2000, Reliant was a net seller on EOL.

Table II-A16. Reliant's Profit From EOL-Reliant Netting Agreement for 24 Churn Days

	Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	Transactions	Volume (MMBtu)	Price	Transactions	Volume (MMBtu)	Price	Reliant's Net Buy From EOL	Profit From the Netting Agreement
11/01/00	10	100,000	$5.07	11	100,000	$5.11	0	($4,700)
11/13/00	19	190,000	$7.41	21	200,000	$7.40	10,000	$3,605
11/30/00	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
12/01/00	25	750,000	$19.21	51	1,530,000	$18.75	[illegible]0,000	$345,000
12/04/00	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/05/00	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/06/00	23	313,000	$38.68	49	490,000	$37.78	177,000	$282,265
12/07/00	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
12/08/00	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
12/11/00	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/13/00	7	108,000	$20.89	67	665,000	$20.72	557,000	($3,549)
12/19/00	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
01/31/01	73	730,000	$14.21	101	1,010,000	$13.62	280,000	$431,267
02/02/01	44	1,320,000	$16.24	80	2,385,000	$15.96	1,065,000	$369,726
02/13/01	17	170,000	$36.78	54	540,000	$34.30	370,000	$421,343
02/28/01	12	120,000	$12.76	21	210,000	$12.93	90,000	($20,429)
03/01/01	15	155,000	$26.03	16	160,000	$22.43	5,000	$558,156
03/02/01	12	360,000	$30.22	30	855,000	$29.46	495,000	$273,158
03/20/01	11	110,000	$11.17	16	160,000	$11.01	50,000	$17,883
03/22/01	13	130,000	$11.09	10	100,000	$10.80	(30,000)	$29,077
03/23/01	31	960,000	$11.12	35	1,050,000	$11.12	90,000	$4,929
04/03/01	12	120,000	$15.09	10	100,000	$14.56	(20,000)	$53,167
06/11/01	21	224,000	$7.23	40	400,000	$6.84	176,000	$89,460
06/13/01	11	110,000	$8.98	41	379,479	$8.51	269,479	$50,950
							Total Profit	$7,267,962

Table II-A17. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes for 24 Churn Days

Transaction Date	Profit From the Netting Agreement	Average Buy Price		GasDaily SoCal Large Packages Midpoint Price Index
		Without the Netting Agreement	Applying Profit From the Netting Agreement, Assuming 60% Flow	
11/01/00	($4,700)	N/A[13]	N/A[13]	$5.20
11/13/00	$3,605	$7.04	$6.79	$7.37
11/30/00	$280,313	$16.25	$14.90	$18.90
12/01/00	$345,000	$18.31	$18.01	$18.50
12/04/00	$233,919	$19.20	$17.74	$21.61
12/05/00	$350,617	$25.00	$24.19	$26.60
12/06/00	$282,265	$36.18	$35.12	$36.25
12/07/00	$186,000	$42.28	$41.81	$42.02
12/08/00	$1,584,545	$51.28	$49.32	$54.66
12/11/00	$1,622,025	$51.24	$48.85	$59.42
12/13/00	($3,549)	$20.72	$20.73	$20.26
12/19/00	$109,255	$19.57	$19.30	$19.56
01/31/01	$431,267	$12.08	$11.05	$13.75
02/02/01	$369,726	$15.61	$15.38	$15.39
02/13/01	$421,343	$33.16	$32.40	$34.53
02/28/01	($20,429)	$13.16	$13.31	$12.96
03/01/01	$558,156	N/A[14]	N/A[14]	$23.95
03/02/01	$273,158	$28.91	$28.54	$27.79
03/20/01	$17,863	$10.65	$10.42	$11.04
03/22/01	$29,077	N/A[15]	N/A[15]	$11.00
03/23/01	$4,929	$11.06	$11.03	$11.13
04/03/01	$53,167	N/A[15]	N/A[15]	$14.71
06/11/01	$89,460	$6.33	$5.99	$6.74
06/13/01	$50,950	$8.33	$8.20	$8.47
Total Profit	**$7,267,962**			

[13]On November 1, 2000, Reliant bought 100,000 MMBtu on EOL and sold back the whole amount. Since the net purchase is zero, the average price cannot be calculated.

[14]On March 1, 2001, Reliant bought 160,000 MMBtu on EOL and sold back 155,000 MMBtu. The net purchase, 5,000 MMBtu, is very small relative to the gross volume (only 1.59 percent). The profit generated by the difference between the buy price and the sell price for the 155,000 MMBtu is $558,156.

[15]On March 22, 2001 and April 3, 2001, Reliant was a net seller on EOL.

Table II-A18. Reliant's Profit From EOL-Reliant Netting Agreement for December 2000 Flow

		Reliant Selling to EOL			Reliant Buying From EOL				
Transaction Date	Churn Day	Transactions	Volume (MMBtu)	Price	Transactions	Volume (MMBtu)	Price	Reliant's Net Buy From EOL	Profit From the Netting Agreement
11/30/00	Yes	19	182,000	$19.82	32	320,000	$18.28	138,000	$280,313
12/1/00	Yes	25	750,000	$19.21	51	1,530,000	$18.75	780,000	$345,000
12/4/00	Yes	21	203,000	$22.54	31	310,000	$21.39	107,000	$233,919
12/5/00	Yes	29	311,000	$27.34	60	600,000	$26.22	289,000	$350,617
12/6/00	Yes	23	313,000	$38.68	49	490,000	$37.78	177,000	$282,265
12/7/00	Yes	23	220,000	$43.85	48	480,000	$43.00	260,000	$186,000
12/8/00	Yes	15	450,000	$57.73	33	990,000	$54.21	540,000	$1,584,545
12/11/00	Yes	56	554,000	$60.77	80	800,000	$57.84	246,000	$1,622,025
12/12/00	No	8	80,000	$29.38	49	490,000	$30.04	410,000	($53,265)
12/13/00	Yes	7	108,000	$20.69	67	665,000	$20.72	557,000	($3,549)
12/14/00	No	2	18,000	$21.06	34	340,000	$19.97	322,000	$19,569
12/15/00	No	5	234,000	$17.79	53	1,590,000	$17.83	1,356,000	($9,764)
12/18/00	No	1	10,000	$20.50	47	470,000	$21.10	460,000	($5,957)
12/19/00	Yes	20	200,000	$20.53	47	470,000	$19.98	270,000	$109,255
12/20/00	No	1	10,000	$21.00	39	390,000	$21.72	380,000	($7,179)
12/21/00	No	6	60,000	$20.33	28	275,000	$18.78	215,000	$93,091
12/22/00	No	2	75,000	$17.67	17	850,000	$18.76	775,000	($82,353)
12/27/00	No	0	0	N/A	22	220,000	$17.17	220,000	$0
12/28/00	No	0	0	N/A	10	300,000	$15.17	300,000	$0
12/29/00	No	2	40,000	$15.50	20	400,000	$14.95	360,000	$22,000
20 Days	10 Churn Days	265	3,818,000		817	11,980,000		8,162,000	$4,966,5325

Total Profit on the Churn Days	$4,990,390
Total Profit on the other Days	-$ 23,859

Table II-A19. EOL-Reliant Netting Agreement's Impact on Physical Spot Trading Outcomes for December 2000 Flow

Transaction Date	Churn Day	Profit From the Netting Agreement	Average Buy Price		GasDaily SoCal Large Packages Midpoint Price Index
			Without the Netting Agreement	Applying Profit From the Netting Agreement, Assuming 60% Flow	
11/30/00	Yes	$280,313	$16.25	$14.90	$18.90
12/1/00	Yes	$345,000	$18.31	$18.01	$18.50
12/4/00	Yes	$233,919	$19.20	$17.74	$21.61
12/5/00	Yes	$350,617	$25.00	$24.19	$26.80
12/6/00	Yes	$282,265	$36.18	$35.12	$36.25
12/7/00	Yes	$186,000	$42.28	$41.81	$42.02
12/8/00	Yes	$1,584,545	$51.28	$49.32	$54.86
12/11/00	Yes	$1,622,025	$51.24	$46.85	$59.42
12/12/00	No	-$53,265	$30.17	$30.26	$32.75
12/13/00	Yes	-$3,549	$20.72	$20.73	$20.26
12/14/00	No	$19,569	$19.91	$19.87	$19.03
12/15/00	No	-$9,764	$17.84	$17.84	$17.06
12/18/00	No	-$5,957	$21.11	$21.12	$20.39
12/19/00	Yes	$109,255	$19.57	$19.30	$19.56
12/20/00	No	-$7,179	$21.74	$21.75	$20.36
12/21/00	No	$93,091	$18.35	$18.06	$18.98
12/22/00	No	-$82,353	$18.87	$18.94	$18.78
12/27/00	No	$0	$17.17	$17.17	$16.64
12/28/00	No	$0	$15.17	$15.17	$14.41
12/29/00	No	$22,000	$14.89	$14.85	$14.33
Volume Weighted Price			$23.71	$23.30	$24.09

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Table II-A20. Reliant's Balance-of-Month Swap Trading Activities and Profits, November 27, 2000 – December 29, 2000

									Profit Statistics	
Trader	Transaction Date	Transaction Time	Buy/ Sell	Swap Volume (MW/hour)	Price	Contract Begin Date	Contract End Date	Counterparty	Profit Generated per Trade	Total Profit Generated
Financial Trader A	11/28/00	3:48 PM	S	-30,000	14.68	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	-$9,114,750	-$9,114,750
	11/30/00	7:48 AM	B	10,000	15.20	12/1/00	12/31/00	MIRANT AMERICAS ENERGY MARKETING, LP	$3,083,050	
		7:52 AM	B	30,000	15.10	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$9,282,150	
		2:25 PM	B	5,000	17.07	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,241,875	
		2:34 PM	B	5,000	16.86	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,275,775	
		2:38 PM	B	10,000	16.94	12/1/00	12/31/00	MIRANT AMERICAS ENERGY MARKETING, LP	$2,523,650	
		3:52 PM	B	10,000	17.50	12/1/00	12/31/00	SEMPRA ENERGY TRADING CORP.	$2,360,050	
		3:54 PM	B	10,000	17.20	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$2,443,050	
		3:55 PM	B	5,000	16.96	12/1/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,258,725	$23,436,125
	12/1/00	12:42 PM	B	15,000	16.05	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$4,158,900	
		12:44 PM	B	5,000	16.27	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,353,300	
		12:45 PM	B	5,000	16.15	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,370,925	
		12:53 PM	S	-5,000	16.56	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	-$1,309,800	
		12:56 PM	S	-5,000	16.12	12/2/00	12/31/00	ENRON NORTH AMERICA CORP.	-$1,375,800	
		1:56 PM	S	-2,000	16.70	12/2/00	12/31/00	SOUTHERN CALIFORNIA GAS COMPANY	-$515,220	$3,682,305
	12/4/00	3:44 PM	B	5,000	18.83	12/5/00	12/31/00	ENRON NORTH AMERICA CORP.	$973,575	
		4:25 PM	S	-5,000	22.39	12/6/00	12/31/00	ENRON NORTH AMERICA CORP.	-$488,900	
		4:26 PM	S	-5,000	22.48	12/6/00	12/31/00	ENRON NORTH AMERICA CORP.	-$486,850	-$99,175
	12/6/00	2:08 PM	S	-5,000	36.32	12/7/00	12/31/00	ENRON NORTH AMERICA CORP.	$1,140,375	$1,140,375
	12/7/00	1:58 PM	S	2,000	37.00	12/8/00	12/31/00	DYNEGY MARKETING AND TRADE	-$548,880	
		2:00 PM	S	10,000	37.28	12/8/00	12/31/00	SEMPRA ENERGY TRADING CORP.	-$2,800,900	
		2:34 PM	S	-10,000	38.00	12/8/00	12/31/00	DYNEGY MARKETING AND TRADE	$2,853,300	-$416,280
	12/12/00	12:38 PM	B	1,800	22.80	12/14/00	12/31/00	AQUILA, INC. D/B/A AQUILA NETWORKS	-$129,405	-$129,405
	12/13/00	8:53 AM	B	8,000	34.00	12/14/00	12/31/00	ENRON NORTH AMERICA CORP.	-$857,280	-$857,280
									Total =	$18,033,745

Table II-A21. Reliant's Balance-of-Month Swap Trading Activities and Profits, February 6, 2001 – February 24, 2001

Trader	Transaction Date	Transaction Time	Buy/ Sell	Swap Volume (MMBtu/d)	Price	Contract Begin Date	Contract End Date	Counterparty	Profit Statistics: Profit Generated per Trade	Profit Statistics: Total Profit Generated
Financial Trader A	2/6/01	10:59 AM	S	-5,000	15.00	2/7/01	2/28/01	SOUTHERN CALIFORNIA GAS COMPANY	-$830,525	-$830,525
	2/12/01	4:00 PM	B	10,000	17.50	2/14/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$702,550	$4,391,000
		4:03 PM	B	5,000	17.75	2/14/01	2/28/01	DUKE ENERGY TRADING & MARKETING, L.L.C.	$332,525	
		4:04 PM	B	10,000	18.00	2/14/01	2/28/01	MIRANT AMERICAS ENERGY MARKETING, LP	$627,550	
		4:08 PM	B	5,000	18.00	2/14/01	2/28/01	DUKE ENERGY TRADING & MARKETING, L.L.C.	$313,775	
		4:13 PM	B	5,000	18.79	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$264,525	
		4:14 PM	B	5,000	19.74	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$183,275	
		4:16 PM	B	5,000	19.30	2/14/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$216,275	
		4:24 PM	B	5,000	18.90	2/13/01	2/28/01	WILLIAMS ENERGY MARKETING & TRADING COMPANY	$410,850	
		4:26 PM	B	5,000	17.85	2/13/01	2/28/01	ENRON NORTH AMERICA CORP.	$334,850	
		4:28 PM	B	5,000	17.50	2/13/01	2/28/01	ENRON NORTH AMERICA CORP.	$382,850	
		4:32 PM	B	5,000	19.10	2/14/01	2/28/01	J. ARON & COMPANY	$231,275	
		4:33 PM	B	5,000	19.25	2/14/01	2/28/01	ENRON NORTH AMERICA CORP.	$220,025	
		4:34 PM	B	5,000	19.80	2/14/01	2/28/01	CINERGY MARKETING & TRADING, LLC	$201,275	

Total = $3,860,475

Appendix II-B: Econometric Analysis of Impact of Reliant Trading on Gas Prices

Intraday EOL Price Analysis

The dependent variable in the analysis is the percentage price change over a trade day (i.e., the intraday change in spot price, measured as the log ratio of the price of the last EOL trade over the price of the first EOL trade). We present two regressions, one with each measure of Reliant's churning activity. The period of interest is November 1, 2000 through June 2001.

For the discrete specification of churning, we estimate the following regression:

$$LCO = \beta 0 + \beta 1\ BNS100K + \beta 2\ DEC2000 + \beta 3\ MONDAY + \beta 4\ LSUMASD + \beta 5\ LNBNDD + \varepsilon,$$

Where:

- LCO is the intraday change in the logarithm of the SoCal spot price.
- BNS100K is a binary variable indicating whether there are buys and sells of at least 100,000 MMBtu/d on a specific day.
- DEC2000 and MONDAY are binary variables indicating that the transaction occurs in December 2000 or for Saturday to Monday flow, respectively.
- LSUMASD and LNBNDD are the interday changes in the logarithms of gas prices at Sumas and San Juan Non-Bondad, respectively.[1]
- ε captures the remaining unexplained component of LCO.

For the continuous specification of churning, we estimate the same regression as above, but for the second churn measure:

$$LCO = \beta_0 + \beta_1\ CHURN + \beta_2\ DEC2000 + \beta_3\ MONDAY + \beta_4\ LSUMASD + \beta_5\ LNBNDD + \varepsilon,$$

Where:

- CHURN is the minimum of sales and purchases (in thousands of MMBtu/d).
- All other variables are as previously defined.

[1] We use the *Gas Daily* Midpoint Price Index.

The results for these two models are provided in Table II-B1 and can be interpreted as follows:

- For both regression specifications, churning is found to be positively correlated with intraday gas price changes and is statistically significant. Stated differently, when Reliant churned, prices rose.
- Changes in gas prices at Sumas and San Juan Non-Bondad, and whether a trade occurs on Friday for weekend flow, are also positively correlated with intraday price changes.
- The coefficient on the December 2000 variable is negative, indicating that intraday price changes were smaller (i.e., more negative) during this period.

Table II-B1. Intraday Regression Results

Churn Measure	Regression Variable	Variable Definition	Parameter Estimate (Absolute value of t statistics)
Purchases and sales of at least 100,000 MMBtu/d	BnS100K	Binary variable indicating whether there are purchases and sales of at least 100,000 MMBtu/d on a specific day	0.0731 (2.74)
	Lsumasd_mid	Logarithm of the interday change in gas price at Sumas	0.4714 (5.82)
	Lnbndd_mid	Logarithm of the interday change in gas price at San Juan Non-Bondad	0.1941 (1.77)
	Monday	Binary variable indicating that the transaction occurs for Sat-Mon flow	0.0557 (2.43)
	Dec2000	Binary variable indicating that the transaction occurs in December 2000	-0.0678 (2.40)
Minimum of total sales and total purchases	Churn	Minimum of total purchases and total sales	0.0002 (2.34)
	Lsumasd_mid	Logarithm of the interday change in gas price at Sumas	0.4919 (6.05)
	Lnbndd_mid	Logarithm of the interday change in gas price at San Juan Non-Bondad	0.1751 (1.55)
	Monday	Binary variable indicating that the transaction occurs for Sat-Mon flow	0.0528 (2.27)
	Dec2000	Binary variable indicating that the transaction occurs in December 2000	-0.0618 (2.19)

Interday EOL Price Analyses and Counterfactual Gas Prices

The calculation of counterfactual gas prices is based on regression analysis similar to that described in the previous section, with three main differences:

First, we include overnight price changes in our analysis. We analyze the interday price change (i.e., the difference between the average EOL price on a trading day and the price on the next trading day).

Second, we model the churn's dynamic effect on prices on days subsequent to the churning days by including lags of the churn variables.[2] In other words, we investigate whether today's churn affects price changes for several days in the future.[3] We estimated our model using different numbers of lags. We found that the effect of churn could not be estimated precisely beyond three lags, so we report results based on the three-lags specifications. Even in some of these specifications, the effects of some lags of churn are not statistically significant. The counterfactual prices that we computed based on regressions including greater numbers of lags were qualitatively similar.

Third, because we are concerned with price dynamics, we also model general mean-reversion in prices that are independent of the effect of churn. Energy prices tend to mean-revert, at least in the medium to long term. High prices induce further exploration and production, leading to increased supply. To the extent that demand is price-sensitive, high prices may also reduce demand. By inducing additional supply and reducing demand, high current prices tend to lead to lower prices in the future. Conversely, low prices today tend to lead to higher prices in the future.

We model the daily price change on the churn variable, lags of the churn variable, and the difference between the lagged EOL price and an estimate of the equilibrium price. For the interday models with the discrete specification of churning, we estimate the following regression:

$$LCC = \beta_0 + \beta_1 LAGCH0 + \beta_2 LAGCH1 + \beta_3 LAGCH2 + \beta_4 LAGCH3 + \beta_5 (LGLGP - EQLOGP) + \varepsilon,$$

Where:

- LCC is the change in the logarithm of the EOL price from the previous day.
- LAGCH0, LAGCH1, LAGCH2, and LAGCH3 are binary variables indicating whether there are purchases and sales of at least 100,000 MMBtu/d on the day associated with the observation, the previous day, two days earlier, and three days earlier.
- LGLGP is the lagged log EOL gas price level.
- EQLOGP is the estimated log equilibrium price.
- ε captures the remaining unexplained component of LCO.

There are two model specifications for each of the two churn definitions (discrete and continuous) for which regressions are performed and counterfactual prices are estimated. These model specifications correspond to alternative methods of specifying the equilibrium price. In the first approach, we include levels of the lagged log price and other independent variables, primarily log prices at various upstream locations, in the regression. Levels of the independent

[2]We also include lags of other independent variables in our regressions.

[3]There are at least two possible reasons why the effects of churn might persist beyond the day on which it occurs. First, churning on one day may push up prices on subsequent days if it changes market psychology and generates momentum. Second, because churning does not change fundamental supply and demand conditions, to the extent that churning results in inflated prices one might expect prices to revert to a "normal" level relatively quickly.

variables determine the "equilibrium" level of the log EOL Topock gas price. To the extent that the lagged log price is above this equilibrium level, prices tend to fall, i.e., price changes are more negative. To the extent that the lagged log price is below this equilibrium level, prices tend to rise, i.e., price changes are more positive. Hence, this type of econometric model is sometimes known as an error-correction model (ECM).[4] Our ECM is specified as follows:

$$\Delta \log p_t^{EOLT} = \alpha + \beta^{NOV} NOV + \beta^{DEC} DEC + \sum_{j=1}^{5} \beta^{DOW_j} DOW_j$$
$$+ \sum_{i=0}^{3} \begin{Bmatrix} \beta_i^{CHURN} CHURN_{t-i} + \beta_i^{Sumas} \Delta \log p_{t-i}^{Sumas} \\ + \beta_i^{SJNB} \Delta \log p_{t-i}^{SJNB} + \beta_i^{DSHOCK} \log DSHOCK_{t-i} \end{Bmatrix}$$
$$+ \lambda \left\{ \log p_{t-1}^{EOLT} - \left[\gamma^{Sumas} \log p_t^{Sumas} + \gamma^{SJNB} \log p_t^{SJNB} + \gamma^{QASYS} \log QASYS \right] \right\} + \varepsilon_t$$

Where:

- $\Delta \log p_t^{EOLTopock}$ is the first difference of the log of the EOL Topock price.
- $CHURN_{t-i}$ is the i'th lag of churn.
- $\Delta \log p_{t-i}^{Sumas}$ and $\Delta \log p_{t-i}^{SJNB}$ are the i'th lags of the first differences of the logs of the Sumas and San Juan Non-Bondad prices.
- $\log DSHOCK_{t-i}$ is the i'th lag of the difference between the log realized ISO system load and the day-ahead forecast.
- NOV and DEC are dummy variables for the months of November and December.
- DOW_j is a dummy variable for day-of-week j. In the estimation, the constant and all five day-of-week dummies are collinear and cannot be estimated uniquely, so we drop one of the day-of-week dummies.
- $\log p_{t-1}^{EOLTopock}$ is the lagged level of the log of the EOL Topock price.
- $\log p_t^{Sumas}$ and $\log p_t^{SJNB}$ are the logs of the contemporaneous Sumas and San-Juan Non-Bondad prices.
- $\log QASYS$ is the log of realized ISO system demand.
- ε_t is the error.

In this specification, $\log p_t^{Sumas}$, $\log p_t^{SJNB}$, and $\log QASYS$ determine an equilibrium log price and λ measures the speed of mean-reversion toward the equilibrium price.

[4] See William Greene, *Econometric Analysis*, 4th ed., Chapter 17, for a brief overview of error-correction and related models.

The second approach is a simplification of the first approach. Rather than modeling an equilibrium price that can change in response to changes in certain variables, we assume that the equilibrium price is fixed, so the regression equation becomes:

$$\Delta \log p_t^{EOLT} = \alpha + \beta^{NOV} NOV + \beta^{DEC} DEC + \sum_{j=1}^{5} \beta^{DOW_j} DOW_j$$
$$\sum_{i=0}^{3} \left\{ \begin{array}{l} \beta_i^{CHURN} CHURN_{t-i} + \beta_i^{\Delta \text{Sumas}} \Delta \log p_{t-i}^{\Delta \text{Sumas}} \\ + \beta_i^{SJNB} \Delta \log p_{t-i}^{SJNB} + \beta_i^{DSHOCK} \log DSHOCK_{t-i} \end{array} \right\}$$
$$+ \lambda \left\{ \log p_{t-1}^{EOLT} - \phi \right\} + \varepsilon_t$$

where ϕ is the log of the estimated long-run equilibrium price. Note that the equilibrium price cannot be estimated if an additive constant is included in the model, i.e., α and $\lambda\phi$ cannot be identified separately.

Which of these models is "better" is ultimately an empirical question. Estimation of the first specification suggests that some of the parameters that determine the equilibrium price, i.e., the γ's, are statistically significantly different from zero. In other words, the *levels* of current upstream prices and California load help predict price movements and hence should be included in the model. The second specification is more parsimonious but less completely models price movements.

For the continuous specification of churning, we estimate the same regression as above but with the second churn measure, i.e., the minimum of sales and purchases (in thousands of MMBtu/d). Thus, the variables LAGCH0–LAGCH3 are continuous variables defined as the minimum of sales and purchases for the observation day (LAGCH0) and three prior days (LAGCH1–LAGCH3).

The regression results are summarized in Table II-B2. We report results for four different specifications based on combinations of the churn variable, i.e., a binary churn variable or the actual volume of churn, and the two methods of modeling the equilibrium price. The results of all specifications are similar and show that:

- Churn tends to elevate prices close to when it occurs, but the effect dissipates after several days.
- Mean-reversion seems to be present but is not necessarily statistically significant. In every specification, the coefficient on the lagged log price is negative, i.e., when prices are high they tend to fall, and when prices are low they tend to rise.

The mean-reversion parameter is statistically significant only in the specifications in which we allow the equilibrium price to vary as a function of data.

Table II-B2. Interday Regression Results

		Model 1		Model 2	
Binary Churn					
Coefficient		**Coef.**	**Se**	**Coef.**	**Se**
Churn	Lag				
	0	0.0975	0.0243	0.1016	0.2468
	1	0.0664	0.0248	0.0634	0.0251
	2	(0.0560)	0.0243	(0.0628)	0.0247
	3	(0.0125)	0.0240	(0.0189)	0.0243
Lagged log EOL price		(0.0621)	0.0170	(0.0112)	0.0099
Continuous Churn					
		Coef.	**Se**	**Coef.**	**Se**
Churn	Lag				
	0	0.0003	0.0001	0.0003	0.0001
	1	0.0002	0.0001	0.0002	0.0001
	2	(0.0002)	0.0001	(0.0002)	0.0001
	3	(0.0001)	0.0001	(0.0001)	0.0001
Lagged log EOL price		(0.0575)	0.0170	(0.0109)	0.0102

All Models The dependent variable is the change in the log price from the previous day.
Model 1 Time-varying equilibrium price is assumed to be a function of independent variables.
Model 2 Constant equilibrium price is assumed.

Table II-B3 shows how counterfactual prices are calculated from the model for an example day—April 3, 2001, one of the Reliant churn days. This example is illustrative and ignores the effects of mean-reversion. The actual log price change for April 3 (the logarithm of the price change from April 2, 2001 to April 3, 2001) is 0.172. Based on a set of regression results (for Model 1 with discrete churn variable), we estimate that churn raises log prices by 0.098 on the day on which it occurs; therefore, we estimate that the price change in the absence of churn would have been 0.075, the value shown in the fourth column. The sum of this counterfactual price change and the previous period's price, 2.520, results in an estimated counterfactual log price of 2.595. This log price corresponds to a price in levels of 13.40, the value shown in the seventh column. The counterfactual log price then forms the basis for the subsequent day's counterfactual price calculation until the fourth day from the churn event, at which point we assume that the actual and counterfactual prices are equal.[5]

[5]This illustrative calculation ignores mean-reversion. When mean-reversion is modeled, not only does the counterfactual price for one day form the starting point for the calculation of the counterfactual price on the subsequent day, but it also affects the extent of mean-reversion on the subsequent day.

Table II-B3. Sample Counterfactual Price Calculation

Date	Churn dummy	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2-Apr-01	0	2.520	0.010	0.000	0.010	2.520	12.43	12.43	0.00
3-Apr-01	1	2.693	0.172	0.098	0.075	2.595	14.77	13.40	1.37
4-Apr-01	0	2.743	0.051	0.066	-0.016	2.579	15.54	13.19	2.35
5-Apr-01	0	2.752	0.009	-0.056	0.065	2.645	15.68	14.08	1.60
6-Apr-01	0	2.664	-0.089	-0.013	-0.076	2.568	14.35	13.05	1.31
9-Apr-01	0	2.613	-0.051	0.000	-0.051	2.613	13.64	13.64	0.00

Where:

- [1] log mean EOL price
- [2] log mean EOL price - log mean EOL price$_{(-1)}$
- [3] Effect of churn (regression coefficients on churn binary variable)
- [4] Counterfactual log price changes ([2] - [3])
- [5] Counterfactual log price (in churn "event" window = [5]$_{(-1)}$ + [4], else = [1])
- [6] Mean EOL price
- [7] Counterfactual price (exp([5]))
- [8] [6] - [7]

Appendix V-A: Details of Data Validation

Introduction

Staff's long-term transaction data consist of sellers' responses to Staff's data request, including backup data in the form of the underlying contracts and contract confirmation notices. We audited contracts and contract confirmations and use this information to validate reported transaction data. In this section, we discuss this audit process and describe how the dataset used for the regression analysis was created.

Auditing Sales Contracts and Confirmations

The first step was to audit contracts and/or contract confirmations to determine if they could be used to validate reported transaction data. To be useful for validation the contract or confirmation had to include name of seller, name of purchaser, sales price, commencement date, termination date, execution date, type of service (flat, on-peak, or off-peak), and delivery point. We also narrowed the number of contracts and confirmations we audited by the following criteria:

- Only fixed-price contracts were audited, i.e., contracts with time-varying prices or prices tied to index or fuel prices were not included.
- Only contracts for delivery at PV, NP15, SP15, COB, or Mid-C were audited.
- Only contracts where the type of service was "on-peak" were audited.

There were 1,630 written contracts or confirmations that met the criteria for auditing. The data entry process was straightforward because the contracts and confirmations were generally unambiguous. To prevent the introduction of error in the audit process, all data entries were double-checked.

The number of audited contracts/confirmations varied widely across sellers. Table V-A1 summarizes the number of audited contracts/confirmations by seller and trading hub.

Table V-A1. Number of Audited Contracts/Confirmations by Seller and Trading Hub

Seller	COB	Mid-C	NP15	PV	SP15	Total
AEP	1	1		20	2	24
Avista	4	5		11	11	31
Cargill-Alliant				1		1
City of Burbank				2		2
Coral			75	7	64	146
Duke	38	79	228	211	233	789
Dynegy				1	1	2
El Paso Merchant	8	21	57	115	114	315
Merrill Lynch				11		11
Morgan Stanley	3	3		15	6	27
PSC of New Mexico				5		5
Reliant	2	5	2	73	72	154
Sempra	9	13	16	28	28	94
Strategic Energy					3	3
TransAlta		2				2
Williams	2	1		12	9	24
Total	67	130	378	512	543	1,630

Of the 1,630 audited contracts/confirmations, 73 transactions were dropped because they were signed before January 1, 2000. We added 26 long-term power purchases by the California Department of Water Resources to the remaining 1,557 audited contracts/confirmations. These contracts have received extensive scrutiny and so their terms are well understood. The California State Auditor's characterization of these contracts was used.[1]

Matching Audited Contracts/Confirmations and Reported Transactions

The audited contracts/confirmations were compared with the sales transactions reported by various sellers. The comparison was made using several specifications, including buyer and seller names, contract price and sales amount (MWh), trading hub, type of service, and execution, commencement, and termination dates.

In most cases the match was perfect. In cases where the match was not perfect, a decision was made as to whether a match was "close enough." Generally, if one field varied slightly between the two data sources but all other fields matched, a match was declared. Specifically, contracts/confirmations were matched with their corresponding reported sale transaction if one of the following conditions was present:

[1]See California State Auditor, Bureau of State Audits, *California Energy Markets: Pressures Have Eased But Cost Risks Remain*, December 2001.

- Execution dates varied by no more than 1 day and all other fields matched (12 matches).
- Prices differed by no more than a few percent and could reasonably be attributed to different interpretations of illegible documents and all other fields matched (28 matches).
- Either the commencement date or termination date varied by 1 year, but all other fields matched (9 matches).
- Either the commencement or termination day of month varied, but all other fields matched, including commencement or termination month and year (69 matches).
- Delivery locations did not match (e.g., PV vs. Mid-C), but all other fields matched (3 matches).
- Buyer names did not match, but the different buyers were affiliated (27 matches).
- Sales amount varied by no more than 25 MWh, but all other fields matched (117 matches).

All audited contracts/confirmations were matched with reported sales transactions. However, not all sellers provided adequate backup documentation to sufficiently validate their reported sales transactions. Table V-A2 provides the number of reported sales transactions that were adequately documented and not adequately documented by sellers.

Table V-A2. Adequacy of Reported Sales Transaction Documentation

	Number of Reported Sales Transactions	
Seller	**Without Adequate Documentation**	**With Adequate Documentation**
Mirant	569	-
Allegheny	170	-
Duke	83	769
El Paso Merchant	61	315
MIECO	35	-
Reliant	35	119
Idaho Power	24	-
Calpine	22	-
Coral	19	146
Morgan Stanley	16	21
Other	17	13
AEP	5	24
PGE	5	-
Avista	4	31
Dynegy	3	1
Merrill Lynch	1	11
Sempra	-	92
Williams	-	15
All	**1,069**	**1,557**

Comparison of Regression Results Based on Validated-Only Data and All Data

Since 40 percent of reported sales transactions lack adequate backup documentation, it is important to determine if the inclusion of these transaction data has a significant effect on regression parameter estimates. To address this issue, we ran a basic "twelve bin" regression (described in Appendix V-C) on the two sets of data. The first set included 1,583 validated transactions (1,557 transactions with adequate backup documentation and 26 transactions from publicly available California power purchase contracts). The second set included 1,583 validated transactions and 1,069 unvalidated transactions. Tables V-A3 and V-A4 summarize parameters estimates for each regression run for the "during" and "after" periods.

Table V-A3. Validated vs. All Comparison: "During" Period

Validated Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	-0.34	0.51	-0.67	0.50	0.76	0.65	0.49	0.18	2.71	0.24	0.25	0.94	38%	34%	42
	3-4 Years	0.54	0.20	2.81	0.36	0.33	1.16	0.14	0.06	2.56	0.18	0.09	2.22	89%	88%	32
	5-8 Years	-0.14	0.17	-0.82	0.07	0.84	0.09	-0.05	0.05	-1.04	-0.09	0.15	-0.59	97%	95%	8
NP15	1-2 Years	1.29	0.29	4.82	1.43	0.31	5.09	0.01	0.13	0.07	-0.04	0.14	-0.34	87%	87%	19
	3-4 Years	2.02	0.32	6.42	2.15	0.39	5.66	0.16	0.05	3.34	0.15	0.05	3.19	85%	84%	52
	5-8 Years	-0.24	0.22	-1.08	-0.08	0.23	-0.34	0.04	0.04	0.97	0.05	0.04	1.25	59%	57%	20
PV	1-2 Years	0.49	0.21	2.41	0.42	0.21	2.05	0.32	0.06	5.11	0.33	0.06	5.38	64%	64%	141
	3-4 Years	0.92	0.26	3.71	0.98	0.26	3.91	0.01	0.05	0.17	0.00	0.05	-0.03	56%	56%	85
	5-8 Years	-0.04	0.13	-0.29	-0.04	0.13	-0.28	0.10	0.03	3.26	0.10	0.03	3.26	65%	65%	43
SP15	1-2 Years	0.37	0.15	2.47	0.60	0.17	3.59	0.19	0.08	2.54	0.11	0.08	1.32	62%	63%	81
	3-4 Years	0.26	0.13	2.16	0.24	0.14	1.80	0.04	0.04	1.05	0.05	0.04	1.12	36%	36%	91
	5-8 Years	0.16	0.20	0.82	0.15	0.20	0.75	0.05	0.04	1.29	0.05	0.04	1.32	48%	48%	46

All Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	0.03	0.27	0.10	0.62	0.42	1.45	0.38	0.09	4.16	0.21	0.13	1.66	43%	43%	101
	3-4 Years	0.52	0.16	3.15	0.26	0.22	1.21	0.13	0.04	3.12	0.19	0.05	3.58	79%	78%	62
	5-8 Years	0.40	0.09	4.43	0.63	0.16	3.84	0.00	0.03	-0.13	-0.01	0.03	-0.41	86%	83%	36
NP15	1-2 Years	1.09	0.31	3.52	0.82	0.34	2.42	0.22	0.13	1.64	0.29	0.14	2.10	65%	62%	40
	3-4 Years	1.89	0.26	6.52	1.76	0.31	5.65	0.14	0.04	3.16	0.14	0.05	3.01	83%	83%	72
	5-8 Years	-0.03	0.26	-0.12	-0.10	0.28	-0.36	0.06	0.05	1.33	0.06	0.05	1.20	63%	63%	24
PV	1-2 Years	0.09	0.19	0.49	0.02	0.19	0.09	0.38	0.06	6.58	0.40	0.06	6.90	49%	49%	221
	3-4 Years	0.42	0.14	3.00	0.46	0.14	3.26	0.09	0.04	2.37	0.08	0.04	2.14	50%	51%	122
	5-8 Years	0.10	0.09	1.10	0.10	0.09	1.11	0.07	0.02	3.36	0.07	0.02	3.35	66%	66%	74
SP15	1-2 Years	0.27	0.15	1.76	0.51	0.17	2.99	0.23	0.08	2.99	0.14	0.08	1.89	60%	60%	89
	3-4 Years	0.28	0.10	2.83	0.29	0.11	2.52	0.07	0.03	2.33	0.07	0.03	2.28	39%	39%	142
	5-8 Years	-0.23	0.07	-3.49	-0.24	0.07	-3.60	0.04	0.03	1.29	0.04	0.03	1.35	46%	47%	83

Table V-A4. Validated vs. All Comparison: "After" Period

Validated Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates: Ordinary Least Squares (OLS) Coeff.	Std. Err.	t-stat	Gas Futures Estimates: With Instrumental Variables (IV) Coeff.	Std. Err.	t-stat	Spot Power Estimates: Ordinary Least Squares (OLS) Coeff.	Std. Err.	t-stat	Spot Power Estimates: With Instrumental Variables (IV) Coeff.	Std. Err.	t-stat	R^2 OLS	R^2 IV	Obs
Mid-C/ COB	1-2 Years	0.70	0.13	5.47	0.54	0.14	3.77	0.01	0.05	0.16	0.04	0.05	0.69	75%	72%	50
	3-4 Years	0.27	0.28	0.95	0.34	0.44	0.78	0.37	0.12	3.03	0.35	0.13	2.72	81%	81%	32
	5-8 Years	0.17	0.16	1.09	0.06	0.20	0.29	0.16	0.07	2.06	0.17	0.08	2.23	89%	89%	24
NP15	1-2 Years	0.69	0.07	10.58	0.64	0.07	9.56	0.09	0.03	3.24	0.10	0.03	3.54	89%	88%	123
	3-4 Years	0.76	0.12	6.51	0.74	0.13	5.89	0.03	0.03	1.11	0.03	0.03	1.16	81%	81%	92
	5-8 Years	0.32	0.10	3.16	0.23	0.10	2.21	0.02	0.03	0.63	0.03	0.03	0.86	71%	70%	60
PV	1-2 Years	0.02	0.32	0.07	0.00	0.32	0.01	0.26	0.13	2.09	0.26	0.13	2.10	13%	13%	93
	3-4 Years	1.01	0.17	6.21	1.00	0.17	6.13	0.00	0.04	-0.05	0.00	0.04	-0.03	73%	73%	65
	5-8 Years	0.00	0.25	0.00	-0.05	0.25	-0.18	0.12	0.06	1.88	0.11	0.06	1.84	28%	28%	46
SP 15	1-2 Years	0.63	0.08	7.81	0.62	0.09	7.00	0.14	0.04	3.91	0.15	0.04	3.85	65%	65%	196
	3-4 Years	0.71	0.12	6.01	0.71	0.12	5.88	0.08	0.03	3.17	0.08	0.03	3.13	81%	81%	103
	5-8 Years	0.64	0.18	3.50	0.64	0.18	3.50	0.20	0.05	3.77	0.20	0.05	3.77	76%	76%	39

All Transactions

Hubs	Time-to-Delivery Class	Gas Futures Estimates: Ordinary Least Squares (OLS) Coeff.	Std. Err.	t-stat	Gas Futures Estimates: With Instrumental Variables (IV) Coeff.	Std. Err.	t-stat	Spot Power Estimates: Ordinary Least Squares (OLS) Coeff.	Std. Err.	t-stat	Spot Power Estimates: With Instrumental Variables (IV) Coeff.	Std. Err.	t-stat	R^2 OLS	R^2 IV	Obs
MIDC/ COB	1-2 Years	0.73	0.12	6.10	0.61	0.13	4.64	0.03	0.05	0.67	0.05	0.05	1.05	78%	78%	91
	3-4 Years	0.76	0.19	3.97	0.87	0.27	3.26	0.38	0.08	4.83	0.37	0.08	4.46	80%	80%	45
	5-8 Years	0.22	0.16	1.39	0.04	0.21	0.19	0.14	0.07	1.94	0.17	0.08	2.16	89%	89%	27
NP 15	1-2 Years	0.71	0.05	13.10	0.68	0.06	12.25	0.06	0.02	3.17	0.06	0.02	3.43	86%	86%	204
	3-4 Years	0.72	0.11	6.87	0.65	0.11	5.71	0.02	0.02	0.90	0.03	0.02	1.17	68%	67%	145
	5-8 Years	0.36	0.11	3.31	0.28	0.12	2.41	0.02	0.03	0.70	0.03	0.03	0.96	53%	51%	80
PV	1-2 Years	0.28	0.18	1.63	0.28	0.18	1.60	0.10	0.06	1.74	0.10	0.06	1.74	20%	20%	197
	3-4 Years	0.67	0.16	4.07	0.65	0.16	3.93	0.02	0.05	0.53	0.03	0.05	0.57	53%	53%	108
	5-8 Years	-0.04	0.22	-0.17	-0.07	0.22	-0.33	0.13	0.06	2.30	0.13	0.06	2.27	34%	34%	56
SP15	1-2 Years	0.70	0.05	13.86	0.72	0.06	12.99	0.07	0.02	3.26	0.06	0.02	3.04	68%	67%	395
	3-4 Years	0.70	0.09	7.89	0.69	0.09	7.28	0.09	0.02	3.82	0.09	0.02	3.88	76%	76%	177
	5-8 Years	0.78	0.16	4.76	0.79	0.16	4.79	0.09	0.04	2.29	0.09	0.04	2.28	69%	69%	63

Tables V-A3 and V-A4 show that for most statistically significant estimates, the estimated parameters based only on validated transactions are close to parameter estimates based on all reported transactions, thus implying that the inclusion of unvalidated transaction data in the regression analysis has a minimal effect on our parameter estimates.

Appendix V-B: Comparison of Forward Gas Curves

Comparison of Forward Gas Curves

Table V-B1. TFS Historical Forward Gas Prices ($/MMBtu)

	Malin				Southern California Border			
	Delivery Dates				Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	7.15	5.58	4.70	n.a.	7.56	5.78	5.10	n.a.
Feb 01	7.67	6.07	5.10	n.a.	8.83	6.50	5.47	n.a.
Mar 01	8.34	6.20	4.86	n.a.	10.17	6.72	5.24	n.a.
Apr 01	9.94	7.34	5.02	n.a.	13.72	8.40	5.32	n.a.
May 01	7.32	5.84	4.66	n.a.	11.22	6.44	4.78	n.a.
Jun 01	4.63	4.33	4.04	n.a.	6.91	4.56	4.06	n.a.

Table V-B2. Williams' Historical Forward Gas Prices ($/MMBtu)

	Malin				Southern California Border			
	Delivery Dates				Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	8.18	6.36	4.32	4.19	8.18	6.36	5.46	5.04
Feb 01	8.61	7.06	4.57	4.53	8.61	7.06	6.03	5.65
Mar 01	9.54	6.45	4.87	4.76	9.99	6.67	5.82	5.59
Apr 01	10.97	6.78	5.19	5.06	13.83	7.75	5.19	5.06
May 01	7.73	5.52	4.66	4.79	11.80	6.01	4.66	4.79
Jun 01	3.75	4.41	4.15	4.29	6.88	4.65	4.07	4.22

Table V-B3. Enron's Historical Forward Gas Prices ($/MMBtu)

	Malin				Southern California Border			
	Delivery Dates				Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	7.73	5.89	4.42	4.06	8.18	6.29	5.18	4.68
Feb 01	7.74	6.62	5.11	4.40	8.59	7.05	5.51	5.06
Mar 01	8.44	6.20	4.84	4.48	10.06	6.70	5.24	5.06
Apr 01	10.16	6.39	4.70	4.26	13.86	7.80	5.16	4.78
May 01	7.80	5.38	4.11	4.06	11.75	6.07	4.61	4.56
Jun 01	4.40	4.19	3.47	3.51	6.90	4.66	3.97	3.99

Table V-B4. Morgan Stanley's Historical Forward Gas Prices ($/MMBtu)

	PG&E Citygate Delivery Dates				Southern California Border Delivery Dates			
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2004	7/1/2001	7/1/2002	7/1/2003	7/1/2004
Jan 01	8.06	6.30	5.51	4.90	7.99	6.24	5.45	4.84
Feb 01	8.63	7.00	5.75	5.20	8.56	6.94	5.69	5.14
Mar 01	9.05	6.41	5.39	5.16	10.06	6.55	5.34	5.09
Apr 01	11.70	6.58	5.08	4.79	13.85	7.55	5.02	4.71
May 01	9.79	5.57	4.67	4.71	11.79	5.85	4.47	4.50
Jun 01	5.78	4.71	4.24	4.25	7.27	4.58	3.98	4.00

TFS vs. Other Forward Gas Curves

Table V-B5. TFS vs. Williams

	Malin Delivery Dates			Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2001	7/1/2002	7/1/2003
Jan 01	14%	14%	-8%	8%	10%	7%
Feb 01	12%	16%	-11%	-3%	9%	10%
Mar 01	14%	4%	0%	-2%	-1%	11%
Apr 01	10%	-8%	3%	1%	-8%	-3%
May 01	6%	-5%	0%	5%	-7%	-2%
Jun 01	-19%	2%	3%	0%	2%	0%

Table V-B6. TFS vs. Enron

	Malin Delivery Dates			Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003	7/1/2001	7/1/2002	7/1/2003
Jan 01	8%	6%	-6%	8%	9%	1%
Feb 01	1%	9%	0%	-3%	8%	1%
Mar 01	1%	0%	0%	-1%	0%	0%
Apr 01	2%	-13%	-6%	1%	-7%	-3%
May 01	7%	-8%	-12%	5%	-8%	-4%
Jun 01	-5%	-3%	-14%	0%	2%	-2%

Table V-B7. TFS vs. Morgan Stanley

	Southern California Border Delivery Dates		
Month	7/1/2001	7/1/2002	7/1/2003
Jan 01	6%	8%	7%
Feb 01	-3%	7%	4%
Mar 01	-1%	-3%	2%
Apr 01	1%	-10%	-6%
May 01	5%	-9%	-6%
Jun 01	5%	0%	-2%

Appendix V-C: Disaggregated Regressions

The following tables summarize spot power and forward gas parameter estimates for various regression formulations. Each regression includes only on-peak transactions that were executed between January 1, 2000 and June 30, 2001 ("during period") or between July 1, 2001 and March 31, 2002 ("after period") for power deliveries at NP15, SP15, COB, PV, or Mid-C. All regressions use TFS' historic natural gas basis and historic NYMEX forwards at Henry Hub. To address the potential simultaneity of the explanatory variables, we perform both the ordinary least squares (OLS) estimation and the instrumental variable (IV) estimation.

Twelve Bin Regressions

In this formulation we aggregate time-to-delivery class periods 1-2 years, 3-4 years, and 5-8 years and the Mid-C/COB hubs. We then run a separate regression for each combination of aggregated hubs and time-to-delivery classes (i.e., 12 regressions). The results of these regressions are summarized in Tables V-C1 and V-C2.

Table V-C1. Twelve Bin Regression for "During" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/ COB	1-2 Years	0.03	0.27	0.10	0.62	0.42	1.45	0.38	0.09	4.16	0.21	0.13	1.66	43%	43%	101
	3-4 Years	0.52	0.16	3.15	0.26	0.22	1.21	0.13	0.04	3.12	0.19	0.05	3.58	79%	78%	62
	5-8 Years	0.40	0.09	4.43	0.63	0.16	3.84	0.00	0.03	-0.13	-0.01	0.03	-0.41	86%	83%	36
NP15	1-2 Years	1.09	0.31	3.52	0.82	0.34	2.42	0.22	0.13	1.64	0.29	0.14	2.10	85%	82%	40
	3-4 Years	1.69	0.26	6.52	1.76	0.31	5.65	0.14	0.04	3.16	0.14	0.05	3.01	83%	83%	72
	5-8 Years	-0.03	0.26	-0.12	-0.10	0.28	-0.38	0.06	0.05	1.33	0.06	0.05	1.20	83%	83%	24
PV	1-2 Years	0.09	0.19	0.49	0.02	0.19	0.09	0.38	0.06	6.58	0.40	0.06	6.90	49%	49%	221
	3-4 Years	0.42	0.14	3.00	0.48	0.14	3.26	0.09	0.04	2.37	0.08	0.04	2.14	50%	51%	122
	5-8 Years	0.10	0.09	1.10	0.10	0.09	1.11	0.07	0.02	3.36	0.07	0.02	3.35	88%	88%	74
SP15	1-2 Years	0.27	0.15	1.76	0.51	0.17	2.99	0.23	0.08	2.99	0.14	0.08	1.69	80%	80%	89
	3-4 Years	0.28	0.10	2.63	0.29	0.11	2.52	0.07	0.03	2.33	0.07	0.03	2.28	39%	39%	142
	5-8 Years	-0.23	0.07	-3.49	-0.24	0.07	-3.60	0.04	0.03	1.29	0.04	0.03	1.35	46%	47%	83

Table V-C2. Twelve Bin Regression for "After" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/COB	1-2 Years	0.73	0.12	6.10	0.61	0.13	4.84	0.03	0.05	0.67	0.05	0.05	1.05	76%	76%	91
	3-4 Years	0.76	0.19	3.97	0.87	0.27	3.26	0.36	0.08	4.83	0.37	0.08	4.46	80%	80%	45
	5-8 Years	0.22	0.16	1.39	0.04	0.21	0.19	0.14	0.07	1.94	0.17	0.08	2.16	89%	89%	27
NP15	1-2 Years	0.71	0.05	13.10	0.68	0.06	12.25	0.08	0.02	3.17	0.08	0.02	3.43	86%	86%	204
	3-4 Years	0.72	0.11	6.87	0.65	0.11	5.71	0.02	0.02	0.90	0.03	0.02	1.17	68%	67%	145
	5-8 Years	0.38	0.11	3.31	0.28	0.12	2.41	0.02	0.03	0.70	0.03	0.03	0.96	53%	51%	80
PV	1-2 Years	0.28	0.18	1.63	0.28	0.18	1.60	0.10	0.06	1.74	0.10	0.06	1.74	20%	20%	197
	3-4 Years	0.67	0.16	4.07	0.65	0.16	3.93	0.02	0.05	0.53	0.03	0.05	0.57	53%	53%	108
	5-8 Years	-0.04	0.22	-0.17	-0.07	0.22	-0.33	0.13	0.06	2.30	0.13	0.06	2.27	34%	34%	56
SP15	1-2 Years	0.70	0.05	13.86	0.72	0.06	12.99	0.07	0.02	3.26	0.08	0.02	3.04	68%	67%	395
	3-4 Years	0.70	0.09	7.69	0.69	0.09	7.28	0.09	0.02	3.82	0.09	0.02	3.88	76%	76%	177
	5-8 Years	0.78	0.16	4.76	0.79	0.16	4.79	0.09	0.04	2.29	0.09	0.04	2.28	69%	69%	63

"Pool by Hub" Regressions

In this formulation, we aggregate time-to-delivery class periods 1-2 years, 3-4 years, and 5-8 years and aggregate all hubs. We run a separate regression for each aggregated time-to-delivery class. The results of these regressions are summarized in Tables V-C3 and V-C4.

Table V-C3. Pool by Hub Regression for "During" Period

Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.29	0.08	3.57	0.46	0.12	3.98	0.33	0.03	9.80	0.27	0.04	6.34	50%	50%	451
3-4 Years	0.31	0.06	5.17	0.34	0.07	4.95	0.12	0.02	6.54	0.11	0.02	5.73	52%	52%	368
5-8 Years	0.04	0.04	0.82	(0.05)	0.05	(1.10)	0.05	0.01	3.36	0.06	0.01	4.18	51%	50%	217

Table V-C4. Pool by Hub Regression for "After" Period

Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.68	0.04	16.74	0.60	0.05	12.08	0.12	0.02	7.15	0.13	0.02	7.41	56%	55%	887
3-4 Years	0.72	0.05	15.03	0.60	0.07	8.34	0.12	0.02	7.12	0.14	0.02	7.35	70%	67%	473
5-8 Years	0.46	0.06	7.23	0.18	0.10	1.77	0.15	0.02	6.83	0.17	0.02	7.22	58%	51%	226

Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies

For each time-to-delivery class, we estimate regressions that include transactions for all hubs. We specify separate intercepts and spot power coefficients for each hub, but constrain the forward gas coefficient to be equal across hubs. Our regression equation is as follows:

$$\log(FP_{it}) = c\ \log(FG_{it}) + \sum_i HubDummy_i \{d_i + b_i \log(SP_{it})\} + e_{it}$$

where d_i and b_i are the hub-specific intercepts and spot power coefficients, respectively. The results of these regressions are summarized in Tables V-C5 and V-C6.

Table V-C5. Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies for "During" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.31	0.05	6.76	0.28	0.05	5.49
	3-4 Years	0.17	0.03	5.31	0.16	0.03	5.11
	5-8 Years	(0.02)	0.03	(0.56)	(0.01)	0.03	(0.48)
NP15	1-2 Years	0.42	0.10	4.17	0.39	0.10	3.75
	3-4 Years	0.21	0.04	5.83	0.21	0.04	5.78
	5-8 Years	0.07	0.04	1.73	0.07	0.04	1.75
PV	1-2 Years	0.35	0.04	8.56	0.32	0.05	7.07
	3-4 Years	0.11	0.02	4.51	0.11	0.02	4.31
	5-8 Years	0.09	0.02	5.46	0.10	0.02	5.76
SP15	1-2 Years	0.26	0.07	3.64	0.22	0.08	2.75
	3-4 Years	0.07	0.03	2.65	0.07	0.03	2.58
	5-8 Years	0.00	0.02	0.00	0.01	0.02	0.30

Time-to-Delivery Class	Gas Futures Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.27	0.10	2.63	0.38	0.12	3.08	52%	52%	451
3-4 Years	0.37	0.07	5.20	0.38	0.08	4.95	57%	56%	398
5-8 Years	(0.04)	0.04	(1.01)	(0.08)	0.05	(1.79)	60%	60%	217

Table V-C8. Pool by Hub Regressions With Additive and Spot Power Interacted Hub Dummies for "After" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.22	0.03	6.79	0.22	0.03	6.77
	3-4 Years	0.21	0.03	6.98	0.21	0.03	7.02
	5-8 Years	0.22	0.03	8.60	0.23	0.03	8.75
NP15	1-2 Years	0.11	0.03	3.52	0.11	0.03	3.50
	3-4 Years	0.01	0.02	0.49	0.01	0.02	0.62
	5-8 Years	0.04	0.03	1.28	0.05	0.03	1.61
PV	1-2 Years	0.08	0.02	3.54	0.08	0.02	3.54
	3-4 Years	0.08	0.02	3.90	0.08	0.02	3.95
	5-8 Years	0.10	0.02	4.13	0.10	0.02	4.20
SP15	1-2 Years	0.08	0.02	3.38	0.08	0.02	3.36
	3-4 Years	0.10	0.02	5.25	0.10	0.02	5.33
	5-8 Years	0.15	0.03	5.35	0.15	0.03	5.44

Time-to-Delivery Class	Gas Futures Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.58	0.05	12.42	0.57	0.05	11.74	62%	62%	887
3-4 Years	0.67	0.06	11.01	0.64	0.07	9.86	76%	76%	473
5-8 Years	0.34	0.07	4.51	0.25	0.08	3.08	70%	70%	226

Pool by Hub Regressions With Spot Power Interacted Hub Dummies

These regressions are identical to those in the previous section except that we exclude hub-specific intercepts. Therefore, the regression equation for each time-to-delivery class is as follows:

$$\log(FP_{it}) = a + c\ \log(FG_{it}) + \sum_i b_i HubDummy_i \bullet \log(SP_{it}) + e_{it}$$

The results of these regressions are summarized in Tables V-C7 and V-C8.

Table V-C7. Pool by Hub Regressions With Spot Power

Interacted Hub Dummies for "During" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/ COB	1-2 Years	0.32	0.04	8.44	0.28	0.04	6.37
	3-4 Years	0.14	0.02	7.33	0.14	0.02	7.17
	5-8 Years	0.05	0.01	3.43	0.05	0.01	3.86
NP15	1-2 Years	0.35	0.04	9.00	0.31	0.05	6.78
	3-4 Years	0.12	0.02	5.87	0.12	0.02	5.72
	5-8 Years	0.06	0.02	3.82	0.07	0.02	4.30
PV	1-2 Years	0.34	0.04	9.47	0.30	0.04	7.30
	3-4 Years	0.12	0.02	6.50	0.12	0.02	6.38
	5-8 Years	0.05	0.01	3.47	0.05	0.01	3.89
SP15	1-2 Years	0.34	0.04	8.26	0.30	0.05	6.05
	3-4 Years	0.11	0.02	5.79	0.11	0.02	5.64
	5-8 Years	0.06	0.01	4.48	0.07	0.01	4.95

Time-to-Delivery Class	Gas Futures Estimates						R^2		Obs
	OLS			IV			OLS	IV	
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.25	0.10	2.47	0.38	0.13	3.06	52%	52%	451
3-4 Years	0.37	0.07	5.40	0.36	0.07	4.91	55%	55%	398
5-8 Years	(0.04)	0.05	(0.80)	(0.08)	0.05	(1.77)	56%	56%	217

Table V-C8. Pool by Hub Regressions With Spot Power Interacted

Hub Dummies for "After" Period

Hub-specific Interacted Dummy on Spot Power	Time-to-Delivery Class	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)		
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat
Mid-C/COB	1-2 Years	0.08	0.02	4.43	0.08	0.02	4.44
	3-4 Years	0.07	0.02	4.02	0.07	0.02	4.03
	5-8 Years	0.13	0.02	5.93	0.13	0.02	6.04
NP15	1-2 Years	0.10	0.02	5.44	0.10	0.02	5.45
	3-4 Years	0.09	0.02	5.48	0.10	0.02	5.46
	5-8 Years	0.15	0.02	7.15	0.16	0.02	7.29
PV	1-2 Years	0.10	0.02	5.91	0.10	0.02	5.92
	3-4 Years	0.10	0.02	5.90	0.10	0.02	5.89
	5-8 Years	0.15	0.02	6.99	0.15	0.02	7.10
SP15	1-2 Years	0.10	0.02	5.63	0.10	0.02	5.63
	3-4 Years	0.09	0.02	5.50	0.10	0.02	5.48
	5-8 Years	0.15	0.02	6.92	0.16	0.02	7.07

Time-to-Delivery Class	Gas Futures Estimates						R^2		Obs
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
1-2 Years	0.59	0.05	12.81	0.59	0.05	12.01	61%	60%	887
3-4 Years	0.65	0.06	10.26	0.64	0.07	9.21	74%	73%	473
5-8 Years	0.30	0.08	3.89	0.23	0.09	2.58	63%	63%	226

"Pool by Class" Regressions

Here we aggregate the Mid-C and COB hubs and pool across all time-to-delivery classes. We run a separate regression for four aggregated hubs. The results of these regressions are summarized in Tables V-C9 and V-C10.

Table V-C9. Pool by Class Regression for "During" Period

Hubs	Gas Futures Estimates						Spot Power Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/COB	0.62	0.15	4.19	0.89	0.21	4.29	0.13	0.04	3.04	0.07	0.05	1.29	38%	38%	199
NP15	1.35	0.16	8.41	1.23	0.17	7.14	0.12	0.05	2.54	0.13	0.05	2.67	73%	72%	136
PV	0.79	0.11	6.99	0.78	0.11	6.87	0.05	0.03	1.79	0.06	0.03	1.85	34%	34%	417
SP15	0.72	0.06	11.73	0.47	0.07	6.35	(0.04)	0.03	(1.27)	0.00	0.03	(0.07)	41%	27%	314

Table V-C10. Pool by Class Regression for "After" Period

Hubs	Gas Futures Estimates						Spot Power Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
Mid-C/COB	0.54	0.08	7.09	0.44	0.09	5.04	0.13	0.03	3.92	0.14	0.03	4.13	77%	76%	163
NP15	0.68	0.04	18.58	0.64	0.04	17.15	0.04	0.01	2.54	0.04	0.01	2.91	77%	76%	429
PV	0.27	0.09	2.89	0.25	0.09	2.67	0.09	0.03	2.74	0.09	0.03	2.75	27%	27%	359
SP15	0.46	0.03	13.64	0.47	0.04	13.24	0.12	0.01	8.54	0.12	0.01	8.41	66%	66%	635

"Pool by Class and Hub" Regressions

We run a single regression by pooling across all time-to-delivery classes and hubs. The results of these regressions are summarized in Table V-C11.

Table V-C11. Pool by Class and Hub Regression Results

Period	Gas Futures Estimates						Spot Power Estimates						R^2		
	Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
"During"	0.61	0.05	13.17	0.63	0.06	11.19	0.07	0.02	4.48	0.07	0.02	3.83	36%	34%	1066
"After"	0.57	0.02	23.11	0.46	0.03	15.02	0.14	0.01	12.32	0.15	0.01	13.17	60%	57%	1586

"No Aggregation" Regression

We run a separate regression for each disaggregated time-to-delivery class and hub. As illustrated in Tables V-C12 and V-C13, the results of these regressions are somewhat irregular due to an insignificant number of transactions in many time-to-delivery class and hub bins.

Table V-C12. No Aggregation Regression for "During" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		Obs
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
COB	1 year	(7.01)	0.45	(15.62)	(6.83)	0.53	(12.57)	(0.85)	0.14	(4.74)	(0.75)	0.18	(4.76)	100%	100%	9
	2 years	2.23	0.28	7.86	2.17	0.30	7.19	(0.24)	0.10	(2.33)	(0.22)	0.11	(2.04)	93%	92%	28
	3 years	0.85	0.17	4.87	0.80	0.21	2.81	0.06	0.05	1.27	0.13	0.06	2.16	98%	98%	24
	4 years	3.88	0.14	28.62	3.88	0.14	28.62	(0.39)	0.04	(9.63)	(0.39)	0.04	(9.63)	100%	100%	4
	5 years	0.00	.	.	0.00	.	.	0.68	.	.	0.68	.	.	100%	100%	2
	7 years	0.00	.	.	0.00	.	.	0.63	.	.	0.63	.	.	100%	100%	3
Mid-C	1 year	(18.86)	18.44	(1.02)	109.08	314.38	0.35	1.51	5.86	0.26	(39.15)	99.92	(0.39)	100%	94%	8
	2 years	0.29	0.14	2.05	1.58	0.55	2.90	0.47	0.04	11.44	0.18	0.13	1.39	91%	80%	56
	3 years	0.46	0.39	1.17	0.81	0.40	1.52	0.15	0.06	2.24	0.13	0.07	2.03	68%	68%	22
	4 years	2.09	0.09	23.72	1.99	0.11	17.51	0.04	0.08	0.55	0.06	0.09	0.63	100%	100%	12
	5 years	0.62	0.19	3.25	0.62	0.19	3.25	0.00	0.04	(0.03)	0.00	0.04	(0.03)	87%	87%	26
	6 years	0.00	.	.	0.00	.	.	0.68	0.00	737.17	0.68	0.00	737.17	.	.	5
NP15	1 year	2.33	.	.	2.33	.	.	(0.04)	.	.	(0.04)	.	.	100%	100%	4
	2 years	1.24	0.38	3.27	0.82	0.42	1.97	0.17	0.16	1.07	0.29	0.17	1.73	64%	60%	36
	3 years	2.21	0.33	6.77	2.29	0.39	5.91	0.12	0.05	2.61	0.12	0.05	2.48	82%	81%	56
	4 Years	0.91	0.62	1.48	1.20	0.99	1.21	0.24	0.17	1.45	0.25	0.17	1.47	92%	92%	18
	5 Years	(0.65)	0.13	(5.07)	(0.81)	0.13	(4.71)	0.07	0.03	2.43	0.08	0.03	2.58	93%	93%	15
	6 Years	2.52	.	.	2.52	.	.	0.00	.	.	0.00	.	.	100%	100%	3
	7 Years	0.52	0.00	.	0.52	0.00	.	(0.04)	0.00	.	(0.04)	0.00	.	100%	100%	6
PV	1 Year	(0.02)	0.90	(0.03)	(0.02)	0.90	(0.03)	0.12	0.18	0.67	0.12	0.18	0.67	39%	39%	48
	2 Years	1.15	0.14	8.34	1.10	0.14	7.98	0.19	0.04	4.71	0.20	0.04	4.99	84%	84%	173
	3 Years	0.46	0.22	2.09	0.58	0.22	2.59	0.09	0.06	1.53	0.06	0.06	1.11	57%	58%	77
	4 Years	0.19	0.15	1.25	0.19	0.15	1.28	0.11	0.04	2.44	0.10	0.04	2.41	50%	50%	45
	5 Years	0.22	0.16	1.38	0.22	0.16	1.39	0.05	0.04	1.30	0.05	0.04	1.29	82%	82%	51
	6 Years	0.03	0.06	0.54	0.03	0.06	0.53	0.10	0.02	6.13	0.10	0.02	6.13	93%	93%	16
	7 Years	0.79	0.56	1.40	0.79	0.56	1.40	(0.22)	0.22	(0.99)	(0.22)	0.22	(0.99)	87%	87%	7
SP15	1 Year	(0.69)	0.38	(1.82)	(0.63)	0.75	(0.83)	0.34	0.18	1.82	0.33	0.21	1.62	78%	78%	31
	2 Years	0.72	0.12	6.21	0.84	0.13	6.55	0.17	0.05	3.30	0.13	0.06	2.28	87%	87%	58
	3 Years	0.22	0.14	1.59	0.27	0.14	1.93	0.07	0.04	1.58	0.06	0.04	1.40	32%	33%	96
	4 Years	0.86	0.20	4.48	0.89	0.21	4.21	0.14	0.04	3.84	0.14	0.04	3.83	73%	73%	46
	5 Years	(0.26)	0.06	(4.38)	(0.27)	0.06	(4.48)	0.04	0.03	1.51	0.05	0.03	1.58	64%	65%	61
	6 Years	(0.10)	0.83	(0.11)	(0.44)	0.85	(0.52)	0.16	0.11	1.47	0.18	0.11	1.59	35%	36%	15
	7 Years	0.76	0.57	1.34	0.76	0.57	1.34	(0.05)	0.07	(0.84)	(0.05)	0.07	(0.84)	99%	99%	7

Table V-C13. No Aggregation Regression for "After" Period

Hubs	Time-to-Delivery Class	Gas Futures Estimates						Spot Power Estimates						R^2		
		Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			Ordinary Least Squares (OLS)			With Instrumental Variables (IV)			OLS	IV	Obs
		Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat	Coeff.	Std. Err.	t-stat			
COB	1 Year	(0.48)	0.67	(0.71)	(0.48)	0.67	(0.71)	1.19	0.22	5.51	1.19	0.22	5.51	99%	99%	4
	2 Years	1.84	0.23	7.98	1.84	0.23	7.98	(0.50)	0.07	(7.05)	(0.50)	0.07	(7.05)	100%	100%	6
	3 Years	0.45	0.04	10.09	0.45	0.04	10.09	0.79	0.02	49.53	0.79	0.02	49.53	100%	100%	5
	6 Years	0.00	.	.	0.00	.	.	1.19	0.00	4,222.98	1.19	0.00	4,222.98	.	.	3
	7 Years	0.00	.	.	0.00	.	.	0.88	.	.	0.88	.	.	.	.	1
Mid-C	1 Year	(0.38)	0.52	(0.73)	(0.39)	0.52	(0.74)	(0.21)	0.10	(2.08)	(0.21)	0.10	(2.08)	95%	95%	8
	2 Years	0.93	0.23	4.00	0.67	0.24	2.76	0.03	0.07	0.48	0.07	0.07	1.06	79%	78%	73
	3 Years	0.33	0.41	0.80	0.43	0.42	1.03	0.35	0.26	1.36	0.36	0.26	1.38	90%	90%	18
	4 Years	1.15	0.37	3.14	1.13	0.38	2.98	0.11	0.19	0.57	0.11	0.19	0.60	68%	68%	22
	5 Years	(0.11)	0.40	(0.27)	(0.11)	0.40	(0.27)	0.48	0.25	1.93	0.48	0.25	1.93	92%	92%	15
	6 Years	0.00	.	.	0.00	.	.	1.16	.	.	1.16	.	.	.	.	1
	7 Years	3.56	1.33	2.68	3.56	1.33	2.69	0.87	0.32	2.73	0.87	0.32	2.73	97%	97%	7
NP15	1 Year	0.36	0.17	2.08	0.36	0.18	2.04	(0.01)	0.08	(0.07)	(0.01)	0.08	(0.07)	86%	86%	18
	2 Years	0.88	0.07	12.32	0.81	0.07	11.14	0.05	0.03	2.07	0.06	0.03	2.55	88%	88%	186
	3 Years	0.81	0.11	7.47	0.84	0.12	6.92	0.02	0.02	0.93	0.02	0.02	0.78	83%	83%	83
	4 Years	0.79	0.22	3.53	0.60	0.24	2.52	0.00	0.06	0.00	0.02	0.06	0.37	52%	49%	62
	5 Years	0.39	0.16	2.48	0.28	0.16	1.76	0.00	0.04	0.08	0.02	0.04	0.40	73%	73%	42
	6 Years	0.18	0.08	2.26	0.19	0.08	2.24	(0.07)	0.01	(4.59)	(0.07)	0.01	(4.59)	95%	95%	13
	7 Years	(0.21)	0.36	(0.59)	(0.29)	0.36	(0.80)	0.01	0.17	0.09	0.01	0.17	0.07	29%	30%	25
PV	1 Year	0.39	6.38	0.06	(1.35)	6.58	(0.20)	(0.56)	1.36	(0.41)	(0.32)	1.38	(0.23)	4%	4%	15
	2 Years	0.78	0.09	8.32	0.77	0.09	8.28	0.06	0.03	2.20	0.06	0.03	2.21	66%	66%	182
	3 Years	1.07	0.31	3.46	1.00	0.31	3.20	(0.01)	0.06	(0.10)	0.00	0.06	(0.01)	54%	54%	55
	4 Years	0.52	0.23	2.24	0.52	0.23	2.21	0.04	0.08	0.56	0.04	0.08	0.57	57%	57%	51
	5 Years	0.21	0.39	0.56	0.22	0.39	0.56	0.14	0.08	1.66	0.14	0.08	1.66	36%	36%	26
	6 Years	0.66	0.46	1.41	0.67	0.48	1.41	0.00	0.18	0.01	0.00	0.18	0.01	98%	98%	11
	7 Years	(0.17)	0.44	(0.39)	(0.32)	0.45	(0.72)	0.02	0.12	0.19	0.04	0.12	0.33	55%	55%	19
SP15	1 Year	0.76	0.52	1.46	0.29	0.66	0.44	0.18	0.20	0.92	0.32	0.23	1.38	48%	45%	27
	2 Years	0.70	0.04	16.20	0.79	0.05	16.66	0.04	0.02	2.82	0.03	0.02	1.83	81%	81%	388
	3 Years	0.74	0.12	6.13	0.72	0.12	5.81	0.08	0.03	2.63	0.08	0.03	2.68	76%	76%	135
	4 Years	0.50	0.19	2.68	0.51	0.19	2.75	0.12	0.04	3.12	0.12	0.04	3.08	77%	77%	42
	5 Years	0.71	0.27	2.61	0.71	0.27	2.61	0.07	0.06	1.15	0.07	0.06	1.15	66%	66%	45
	6 Years	1.30	1.17	1.11	1.30	1.17	1.11	0.16	0.08	1.96	0.16	0.08	1.96	64%	64%	11
	7 Years	(0.58)	0.12	(4.96)	(0.58)	0.12	(4.96)	0.38	0.03	10.91	0.38	0.03	10.91	99%	99%	7

Appendix V-D: Serial Correlation

Our statistical model attempts to capture the main determinants of forward power prices. Inference based on standard OLS or IV coefficient estimates and standard errors assumes that there is no systematic variation in the portion of the dependent variable, in this case the price of forward power, that is not explained by the statistical model (i.e., the error). Serial correlation occurs when the errors in the estimates are not independent. In the presence of serial correlation, standard errors from conventional OLS and IV estimation tend to be understated and, therefore, claims of statistical significance of model coefficients tend to be overstated.[1]

To test the sensitivity of our regression results to the potential presence of serial correlation, we re-estimated one model specification using techniques that produce standard errors that explicitly account for the presence of serial correlation. Because our data are organized as an unbalanced panel (i.e., we have contracts signed at irregularly spaced points in time for different delivery periods and locations), correcting for serial correlation could be computationally intensive. We have chosen a method that requires minimal amounts of computation but requires some aggregation of the underlying data. We perform a panel version of Prais-Winsten estimation[2] and treat each combination of hub and time-to-delivery as a subpanel.[3] Within each subpanel, multiple contracts signed on the same day are averaged. The Prais-Winsten estimation is performed on these aggregated data. We constrain the extent of serial correlation to be equal across subpanels. The results are shown in Table V-D1 below. The table also shows OLS results on the aggregated data for comparison with our OLS results on the disaggregated data.[4]

[1] See William Greene, *Econometric Analysis*, 4th ed., Chapter 13, for a description of how the presence of serial correlation affects statistical inference.

[2] See William Greene, *Econometric Analysis*, 4th ed., p. 546.

[3] Our estimation is performed using Stata's "xtpsce" command. See the Stata, version 7 manuals for the details of this command.

[4] The OLS parameter estimates for the disaggregated data match the estimates in Table V-3, but the standard errors are slightly different. The parameter estimates in Table V-D1 are the result of a single stacked regression rather than four separate hub-specific regressions. In this particular stacked regression, we constrain our estimate of the error variance to be equal across hubs. This constraint affects estimated standard errors but not parameter estimates.

Table V-D1. Prais-Winsten Estimates of the Spot Power Coefficient

Hubs	Time-to-Delivery Class	Coefficient on log spot power					
		Disaggregated Data OLS (stacked)		Aggregated Data OLS (stacked)		Prais-Winsten	
		Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Mid-C/ COB	1 Year	0.375	0.053	0.364	0.061	0.422	0.056
	2 Years	0.135	0.076	0.163	0.088	0.162	0.080
	3 Years	-0.004	0.131	-0.016	0.134	-0.018	0.123
NP15	1 Year	0.219	0.129	0.227	0.160	0.201	0.141
	2 Years	0.141	0.091	0.112	0.124	0.104	0.113
	3 Years	0.063	0.132	0.057	0.160	0.059	0.142
PV	1 Year	0.383	0.045	0.314	0.058	0.246	0.053
	2 Years	0.088	0.045	0.079	0.057	0.100	0.051
	3 Years	0.070	0.059	0.066	0.079	0.064	0.074
SP15	1 Year	0.232	0.066	0.207	0.074	0.225	0.070
	2 Years	0.072	0.044	0.017	0.058	0.004	0.055
	3 Years	0.037	0.065	0.043	0.076	0.044	0.069
N			1066		598		598
rho							0.433

Neither aggregation nor controlling for serial correlation produces qualitatively different results. That is, the coefficients do not differ between the OLS disaggregated case and the OLS aggregated case, nor between the OLS aggregated case and the Prais-Winsten case. The standard errors in the OLS aggregated case and the Prais-Winsten case are also similar. This last result shows that serial correlation does not affect the precision of our estimates. In part, this is because the estimated degree of serial correlation, labeled "rho" in Table V-D1, is modest. In addition, there are significant gaps in the data. Successive transactions with the same delivery location and time to delivery may be several days apart. Even if serial correlation is present, if trades are spaced far enough apart in time, it may not matter.[5]

[5]Serial correlation is a more serious issue for similar analyses based on daily index prices. See Harvey and Hogan, *op. cit.*, note 2.

Appendix IX-A: A Detailed Description of Trader 1's Trading Positions and Profits for the June 14, 2001 Market Test

This appendix describes trading of NYMEX look-alike swaps on EOL on June 14, 2001 by one trader. As described in detail in Chapter III, one of the most common OTC derivative products is known as the OTC swap or the NYMEX look-alike swap. This swap derives its value from the price of the NYMEX natural gas futures contract. Henry Hub physical transactions strongly correlate with the NYMEX futures and the related OTC NYMEX look-alike swaps because the NYMEX futures directly settle based on the Henry Hub physical delivery price.

Following the run-up in prices in the next-day physical market from 10:12 a.m. through 10:35 a.m., trader 1 of the Central desk entered short transactions in July delivery OTC swaps through four sales of 15,000 MMBtu swaps at 4.095, 4.09, 4.085, and 4.09, respectively (where the four average $4.09).[1] The total volume amounted to 60,000 MMBtu in July delivery OTC swaps. That is, the trader promised to sell 60,000 MMBtu of gas every day for the next month (July) at an average price of $4.09/MMBtu. If the NYMEX price for the July gas on a given day in June is more that $4.09, then the trader has incurred losses for that day because he is selling gas (whether he actually has the gas or needs to buy it) at a price below the market value. Conversely, if the price is below $4.09, then his position is profitable because he is selling gas for more than the market value.

[1]Data reflect that the Enron trader was net short OTC swaps prior to the beginning of the day. However, because the market first rose and then fell back to the approximate opening price, Staff only allocated the financial trades that occurred during the physical manipulation as vehicles potentially purchased to profit by the manipulation.

Recall that this manipulation involved first selling slowly into the market and then repurchasing quickly. The strategy did not involve additional downward pressure in the physical market at the end of the manipulation as was displayed in the July 19 manipulation. In that manipulation, Staff allocated the opening short position as a vehicle to profit from the manipulation due to Enron's apparent intent to push the market down further. The data reflected this intent where they showed Enron was a net seller of Henry Hub next-day physical gas for the day. This was also supported by depositional testimony.

These swaps have a term of 31 days and the quoted volume is a daily volume; therefore, 60,000 multiplied by 31 days yields an intraday short position of 1,860,000 MMBtu. Trader 1 then increased the short position by the additional sale of another 15,000 MMBtu/d (for a total of 465,000 MMBtu) at the price of $4.045/MMBtu at 11:24 a.m., resulting in a total increase of his intraday short position to 75,000 MMBtu/d (for a total of 2,325,000 MMBtu) and an average sell price of $4.081. In essence, the trader has promised to sell 75,000 MMBtu of gas for every day of July at an average price of $4.081.

Between 2:19 and 2:20 p.m., after the market test ceased, trader 1 reduced his net short position by buying 25,000 MMBtu/d at $4.05. Here, the trader has promised to purchase 25,000 MMBtu of gas for each day in July at a price of $4.05. If the NYMEX price for July gas on a given day in June is above $4.05, the trader earns a profit because he is buying gas below market value. If the price is below $4.05, he is incurring a loss because he is buying gas above the market price. This purchase is used to meet and close out 25,000 MMBtu of his promise to sell. Since the trader bought at $.031 less than his obligation to sell, he generates a profit of $24,025.[2]

Trader 1 then further reduced his short position by 30,000 MMBtu/d. He bought the 30,000 MMBtu/d at an average price of $4.0883, generating a loss of $6,820 on this portion of his position or a net gain of only $17,205. He is effectively buying the gas at $4.0883 for every day of July to fulfill his promise to sell the gas at $4.081, generating a loss of $.0073/MMBtu for each of the 31 days in July.

Trader 1 retained the remaining 20,000 MMBtu/d of his short position until the end of trading, when the market closed at $4.02. This generated additional profits of $37,820. He now has a promise to sell 20,000 MMBtu of gas for each day of July at a price of $4.081 and can meet that obligation by purchasing gas at a market value of $4.02, generating a profit of $37,820.

Trader 1's total profit arising from the market test amounted to $55,025.

[2]Trader 1 sold at an average price of $4.081 and bought at an average price of $4.05, yielding a profit of 3.1 cents/MMBtu ($.031 multiplied by 25,000 MMBtu/d and then multiplied by 31 days in the contract yields a profit of $24,025).